STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE JACOB S. GERTSMAN

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF (2017)	)	**BPU DOCKET No. ER17030308** **OAL DOCKET No. PUC 04989-17**

DIRECT TESTIMONY OF ANDREA C. CRANE
ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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PUBLIC VERSION

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is 2805 East Oakland Park Boulevard, # 401, Ft. Lauderdale, Florida 33308.

Q. By whom are you employed and in what capacity?

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989. I became President of the firm in March 2008.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in over 400 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Washington, West Virginia and the District of Columbia. These proceedings involved electric, gas, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony since January 2008 is included in Appendix A.

Q. What is your educational background?

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On March 30, 2017, Atlantic City Electric Company (“ACE” or “Company”) filed a Petition with the New Jersey Board of Public Utilities (“BPU” or “Board”) requesting an electric base rate increase of $70.160 million.[1] The Company’s case was based on a Test Year consisting of the twelve months ending July 31, 2017. As originally filed, ACE’s

1 All amounts referenced in this testimony exclude sales and use tax (“SUT”) unless otherwise noted.

revenue requirement reflected actual results for five months (Aug-Dec, 2016) and projected results for seven months (Jan.-July, 2017). On July 14, 2017, ACE updated its Test Year to reflect nine months of actual data and three months of projections ("9+3 Update"). ACE will be filing an additional update once it has a full twelve months of actual Test Year data ("12+0 Update"). Rate Counsel's testimony is based on the Company's original filing. My testimony will be updated once ACE files its 12+0 Update.

ACE's parent company, Pepco Holdings, Inc. ("PHI"), completed a merger with Exelon Corporation ("Exelon") on March 23, 2016. In this base rate case filing, ACE is requesting authorization to defer "costs to achieve" associated with that merger. ACE has included the estimated costs to achieve in rate base and plans to request recovery of the associated amortization expense in its next base rate case. Finally, in addition to its requested distribution rate increase, ACE is also seeking authorization to implement a System Renewal Recovery Charge ("SRRC"), which would allow the Company to recover the revenue requirement associated with most capital investments between base rate cases.

The Columbia Group, Inc. was engaged by The New Jersey Division of Rate Counsel ("Rate Counsel") to review the Company's Petition and to provide recommendations to the BPU regarding the Company's revenue requirement claim. In developing my recommendations, I have relied upon the cost of capital and capital structure testimony of Matthew I. Kahal.

Q. What are the most significant issues in this rate proceeding?

A. The most significant issues driving the rate increase request are the Company's claim for a cost of equity of 10.1%; the Company's proposals to include post-test year plant additions and a prepaid pension asset in rate base; the absence of a consolidated income tax adjustment; salary and wage increases through December 31, 2018; significant increases in incentive compensation costs; and a projected decline in distribution revenues. ACE's last electric base rate case was resolved by Stipulation with new rates effective August 24, 2016. That case was based on a Test Year ending December 31, 2015.

Q. Has the Company had significant rate increases over the past few years?

A. Yes, it has. Following are the rate increases received by the Company since 2010:

Date	Amount ($ Millions)	Percentage
August 24, 2016	$45.00	13.4%
September 1, 2014	$19.00	6.1%
July 1, 2013	$25.50	8.7%
November 1, 2012	$28.05	10.7%
June 1, 2010	$20.00	8.6%

Over the past seven years, the Company has received rate increases of $137.55 million, or 47.5%. The increase of $70.160 million being requested in this case represents an increase of 18.8% over pro forma distribution revenues at present rates.

III. SUMMARY OF CONCLUSIONS

Q. What are your conclusions concerning the Company's revenue requirement and its need for rate relief?

A. Based on my analysis of the Company's filing, and other documentation in this case, my conclusions are as follows:

1. The twelve months ending July 31, 2017 is a reasonable Test Year to use in this case to evaluate the reasonableness of the Company's claims.
2. Based on the testimony of Mr. Kahal, the Company has a cost of equity of 9.0% and an overall cost of capital for its electric distribution operations of 7.28%.
3. ACE has pro forma distribution rate base of $1,103.757 million (see Schedule ACC-3).[2]
4. The Company has pro forma electric distribution operating income at present rates of $77.237 million (see Schedule ACC-15).
5. ACE has a pro forma, electric distribution revenue deficiency of $5.373 million (see Schedule ACC-1). This is in contrast to the Company's claimed revenue deficiency of $70.160 million.
6. ACE's request to include in rate base certain unamortized costs to achieve associated with the Exelon merger should be denied.

[2] Schedules ACC-1 and ACC-38 are summary schedules, ACC-2 is a cost of capital schedule, ACC-3 to ACC-14 are rate base schedules, and ACC-15 to ACC-37 are operating income schedules.

7. ACE's request to implement a new tracking mechanism, the SRRC, to recover the revenue requirement associated with investment between base rate cases should be rejected.

8. Rate Counsel's revenue requirement recommendations will be updated once the Company files its actual Test Year results, based on the twelve months ending July 31, 2017.

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that ACE is requesting in this case?

A. The Company utilized the following capital structure and cost of capital in its filing:

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	49.86%	5.56%	2.77%
Common Equity	50.14%	10.10%	5.06%
Total	100.00%		7.83%

Q. What is the capital structure and overall cost of capital that Rate Counsel is recommending for ACE?

A. As shown on Schedule MIK-1 of Mr. Kahal's testimony, Rate Counsel is recommending an overall cost of capital for ACE of 7.28% based on the following capital structure and cost rates:

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	49.86%	5.56%	2.77%
Common Equity	50.14%	9.00%	4.51%
Total	100.00%		7.28%

Mr. Kahal has accepted the Company's capital structure and cost of debt. However, he is recommending a reduction to the Company's claimed cost of equity. Mr. Kahal's adjustment results in a pro forma overall cost of capital of 7.28%, which is the overall cost of capital that I have used to determine the Company's pro forma required income, as shown on summary Schedule ACC-1, based on my recommended rate base. I then compared this required income to pro forma income at present rates to determine the Company's need for rate relief. As shown on Schedule ACC-1, my recommendations indicate that the Company currently has an electric base distribution deficiency of $5.373 million.

VI. RATE BASE ISSUES

A. Utility Plant-in-Service

Q. How did ACE determine its utility plant-in-service claim in this case?

A. The Company began with its estimated utility plant-in-service balances at July 31, 2017, the end of the Test Year. ACE then made two post-test year adjustments. First, ACE included an adjustment to reflect projected plant additions through January 31, 2018 of

$52.691 million. ACE included seven categories of plant in this adjustment: Capacity Expansion, Corrective Capital Replacement, System Performance, T&D Automation, Emergency, Customer Driven, and General Plant. The Company included depreciation reserve additions related to these post-test year plant additions as well as additions to the deferred income tax reserve associated with post-test year plant. ACE also removed retirements expected to be made from August 1, 2017 through January 31, 2018 from both its utility plant-in-service and depreciation reserve claims. The net result of ACE's first post-test year plant adjustment was an increase to rate base of $48.740 million.

ACE included a similar adjustment to reflect projected additions from February 1, 2018 through March 31, 2018 of $6.440 million. Once again, the Company also made corresponding adjustments to retirements, the depreciation reserve and the deferred income tax reserve. ACE's second post-test year plant adjustment resulted in an increase to rate base of $5.371 million. With regard to plant additions from February 1, 2018 to March 31, 2018, the Company did not include either Customer Driven plant additions or additions to General Plant.

Q. Are you recommending any adjustments to the Company's claim for utility plant-in- service?

A. Yes, I am recommending that the BPU eliminate all post-test year plant additions from the Company's rate base.

Q. What is the basis for your recommendation to exclude these post-test year plant

additions from rate base?

A. The Company's claim results in a mismatch among the components of the regulatory triad used to set rates in this case and is inconsistent with BPU precedent regarding the inclusion of post-test year plant additions in rate base. Ratesetting is based on a regulatory triad that attempts to match revenues, expenses, and rate base investment during a twelve-month test year period. While the Company included post-test year plant additions through March 31, 2018, neither its depreciation reserve claim nor its claim for the deferred income tax reserve included all reserve additions through March 31, 2018, but only the relatively small additions associated with incremental plant. More importantly, the Company did not attempt to limit post-test year plant additions to projects that met the "major in nature and consequence" criteria of the BPU, nor did it limit such additions to those completed within six months of the end of the Test Year. In fact, ACE is proposing that over $6.4 million of utility plant additions from February-March 2018 be included in rate base.

	Aug. 2017-Jan. 2018	Feb.-March 2018
Capacity Expansion	$711,237	$41,613
Corrective Capital Replacement	$4,363,822	$584,738
System Performance	$16,815,564	$2,723,846
T&D Automation	$4,541,171	$339,782
Emergency	$11,406,618	$2,750,071
Customer Driven	$6,261,194	-
General Plant	$8,591,215	-
Total	$52,690,821	$6,440,020

Q. What is your understanding of BPU policy with regard to post-test year plant

additions?

A. I am aware that the New Jersey BPU has in the past permitted certain post-test year plant-in-service additions to be included in rate base. As stated in the Board's Decision on Motion for Determination of Test Year and Appropriate Time Period for Adjustments, Elizabethtown Water Company, Docket No. WR8504330, page 2 ("Elizabethtown Order"):

> With regard to the second issue, that is, the appropriate time period and standard to apply to out-of-period adjustments, the standard that shall be applied and shall govern petitioner's filing and proofs is that which the Board has consistently applied, the "known and measurable" standard. Known and measurable changes to the test year must be (1) prudent and major in nature and consequence, (2) carefully quantified through proofs which (3) manifest convincingly reliable data. The Board recognizes that known and measurable changes to the test year, by definition, reflect future contingencies; but in order to prevail, petitioner must quantify such adjustments by reliable forecasting techniques reflected in the record.

It is clear that the Company has not met the criteria specified by the BPU for the inclusion of post-test year projects in rate base. ACE has not limited its post-test year plant-in-service claim to projects that are "major in nature and consequence." Instead, the Company has included budgeted plant additions through March 2018 in a variety of categories without attempting to distinguish those that may meet the "major in nature and consequence" criteria.

As shown in Schedule JCZ-12.1 to Mr. Ziminsky's testimony, the vast majority of the post-test year projects being claimed by the Company for the period August 1, 2017 to January 1, 2018 are under $1 million in cost, and many of these projects are below $100,000. Clearly, such projects are not "major in nature and consequence" and do not meet the criteria spelled out in the Elizabethtown Order for inclusion of post-test year projects in rate base. I also have concerns about the nature of the projects being claimed by ACE in its post-test year rate base adjustment. For example, Customer Driven investment relates to projects resulting from normal growth of the utility system – and these projects generate additional revenue that mitigates the impact of this investment on Company earnings. Claims for future investment relating to emergency restoration after major storms are speculative in that no one can predict with certainty when a storm will occur or how much damage will result from a storm. I have similar concerns about the other plant categories included in the Company's claim. For example, General Plant additions include $13,000 for a security system and related equipment, $29,000 in meter tools, and $84,000 for office furniture. It is difficult to see how these constitute projects that are major in nature and consequence. I also have concerns regarding projects to replace aging infrastructure. Infrastructure replacement is an integral, on-going part of providing regulated electric distribution service and these costs should be recovered through the normal Test Year criteria, not given special treatment by being afforded the Elizabethtown exception relating to projects that are "major in nature and consequence". Instead of attempting to identify specific projects that may meet the criteria set out in the Elizabethtown case, ACE has simply included its entire projected plant-in-service additions in rate base. While Mr. Sullivan states on page 26 of his testimony that "…the Company is requesting recovery of only a portion of the amount being invested in the distribution system over the course of the two post-test year adjustment periods," it appears that the only projects that were not included by ACE are those that are not projected to go into service by March 31, 2018.

Clearly, the projects included in the Company's post-test year claim that are projected to go into service from February 1, 2018 – March 31, 2018 do not meet the Elizabethtown criteria. With regard to the remaining projects, ACE has not demonstrated that even these projects meet the standards set out in the Elizabethtown Order, and in fact has included projects that are clearly not major in nature and consequence. Accordingly, I recommend that the Company's claim for inclusion of post-test year plant additions be denied. My adjustment to eliminate the Company's claim for August 1, 2017 – January 31, 2018 plant additions is shown in Schedule ACC-4. My adjustment to eliminate the Company's claim for January-February, 2018 plant additions is shown in Schedule ACC-5.

B. <u>Plant Held For Future Use</u>

Q. Has the Company included any plant held for future use in rate base?

A. Yes, the Company has included $6.584 million of plant held for future use in its rate base claim.

Q. What is plant held for future use?

A. Plant held for future use is plant that is not currently used in the provision of utility service to customers but which the Company claims has some potential to be used in the future to serve customers. One common example is land being held as a possible future site for a Company facility.

Q. Have you included plant held for future use in your revenue requirement recommendation?

A. No, I have not. This plant is, by definition, not used and useful in providing utility service to current customers. Moreover, this plant may never be used in the provision of utility service. The Company's claim for plant held for future use includes plant that was acquired by the Company as far back as 1985, over 30 years ago. Including this plant in rate base is speculative until such time as the plant is actually in-service and used and useful in the provision of utility service. In any case, this plant was not in-service at July 31, 2017, the end of the Test Year in this case. Nor is any of this plant anticipated to be in-service by January 1, 2018, six months after the end of the Test Year. Accordingly, I am recommending that all plant held for future use be eliminated from the Company's rate base claim in this case. My adjustment is shown in Schedule ACC-6.

C. <u>Cash Working Capital</u>

Q. What is cash working capital?

A. Cash working capital is the amount of cash that is required by a utility in order to cover cash outflows between the time that revenues are received from customers and the time that expenses must be paid. For example, assume that a utility bills its customers monthly and that it receives monthly revenues approximately 30 days after the midpoint of the date that service is provided. If the Company pays its employees weekly, it will have a need for cash prior to receiving the monthly revenue stream. If, on the other hand, the Company pays its interest expense semi-annually, it will receive these revenues well in advance of needing the funds to pay interest expense.

Q. Do utilities always have a positive cash working capital requirement?

A. No, they do not. The actual amount and timing of cash flows dictate whether or not a utility requires a cash working capital allowance. Therefore, one should examine actual cash flows through a lead/lag study in order to accurately measure a utility's need for cash working capital.

Q. Please describe the Company's claim for cash working capital.

A. The Company has based its cash working capital claim on a lead-lag study. The Company first calculated its revenue and expense leads/lags, and then applied those leads/lags to its Test Year costs in order to develop the cash working capital claim reflected in the Company's rate base claim. In addition, the Company made an adjustment to reflect the incremental cash working capital associated with its pro forma adjustments.

Q. Are you recommending any adjustments to the Company's cash working capital claim?

A. Yes, I am recommending ACE's cash working capital claim be revised to eliminate cash working capital associated with non-cash items, such as depreciation and amortization expense. Moreover, I recommend that non-contractual costs, such as utility operating income, be excluded from the lead/lag study. Finally, I recommend that the lead/lag study be revised to include the lag on interest expense. This adjustment reflects the fact that revenues are collected in rates for interest expense on a monthly basis but debt payments are made semi-annually to the bondholders. It should be noted that the Company's lead/lag study was generally based on 2015 data, except for the collection lag, which was based on 2016 data.[3] Therefore, the lead/lag days used in the study may not be representative of current conditions. Nevertheless, I have utilized the lead/lag days reflected in the Company's filing to quantify my adjustments.

Q. Please explain how ACE has treated the non-cash items you have eliminated in your adjustments to cash working capital.

A. ACE has included depreciation and amortization expenses and invested capital in the lead/lag calculation as expenses with zero-lag days.[4] The inclusion of these items with a zero lag has a very significant impact on the cash working capital requirement because it assumes that the Company has a continuous need for cash to meet these costs and that this cash is required at the same time that utility service is provided, i.e., there is no lag.

Q. Why does ACE seek to include these items at a zero lag?

A. Mr. Ziminsky did not provide any testimony as to why he believes that these items should be included with a zero lag.

3 Per the Testimony of Mr. Ziminsky at page 10, lines 20-21.
4 Note that ACE excluded any cash working capital requirement associated with either current or deferred taxes from its cash working capital claim in this case.

Q. What is the basis for your recommendation to exclude depreciation and amortization expense entirely from the lead/lag study?

A. It is inappropriate to include depreciation and amortization expense in a utility's cash working capital claim because these costs do not result in cash outflows by the utility. ACE does not make cash payments for depreciation or amortization on a specified date. The purpose of a lead/lag study is to match cash inflows, or revenues, with cash outflows, or expenses. Cash working capital reflects the need for investor-supplied funds to meet the day-to-day expenses of operations that arise from the timing differences between when ACE has to expend money to pay the expenses of operation and when revenues for utility service are received by the utility. Only items for which actual out-of-pocket cash expenditures are required should be included in a cash working capital allowance. Therefore, at Schedule ACC-7, I have made an adjustment to eliminate the cash working claims associated with depreciation and amortization expense from ACE's cash working capital claim.

Q. Please explain why you have rejected the Company's claim for zero lag days for return on invested capital.

A. Return on invested capital includes a cost of equity component as well as a cost of debt. The cost of debt component, i.e., interest expense, is addressed below. That component of invested capital has a lag of 91.25 days, assuming semi-annual interest payments, not the zero lag included in the Company's lead/lag study.

With regard to the cost of equity, this does not represent a contractual obligation of

ACE. The Company is under no obligation to make payments to its stockholders. While ACE may make dividend payments, they are contractually not obligated to do so. Moreover, even if dividend payments are made, they are generally made no more frequently than quarterly. They are certainly not made on a daily basis, which is the assumption inherent in the use of a zero lag. In addition, companies generally retain a portion of their earnings rather than paying out all earnings as dividends, another fact not taken into account in the Company's study. Therefore, it is inappropriate to reflect a zero lag, and to correspondingly increase the Company's cash working capital, for the return on equity.

Q. Has ACE reflected a reduction in cash working capital related to the lag in its payment of interest expense?

A. No, it has not. The Company has failed to reflect the fact that the revenue requirement includes a component for interest expense, which is a contractual obligation of the utility.

Q. How is working capital generated by the Company's lag in the payment of its interest expense?

A. ACE collects revenues from ratepayers for interest expense on a monthly basis but pays its bondholders for interest only twice a year. Therefore, on average, the accrued interest funds are available to the Company, at no cost, to finance their operations between the time they collect the interest from customers and the time that interest payments are made to bondholders.

Q. How should this cost-free source of funds be reflected for ratemaking purposes?

A. The lag in the payment of interest expense must be reflected in the cash working capital calculation so that ratepayers are compensated for providing a cost-free source of capital to ACE prior to the interest payments being made. In developing my adjustment, I included the interest expense at a lag of 91.25 days, which reflects semi-annual payments of interest.[5]

Q. What are the results of your cash working capital adjustments?

A. I have eliminated the zero lag days used by the Company for depreciation and amortization and invested capital and reflected the lag in the payment of interest expense. My adjustments result in a reduction of $22.293 million to the Company's cash working capital claim, as shown in Schedule ACC-7.

Q. Do you have any additional comments regarding cash working capital?

A. Yes. I have not attempted to reflect the impact of my recommended expense adjustments in my pro forma cash working capital recommendation. However, I recommend that the cash working capital requirement be updated to reflect the actual level of expenses, including interest expense, found by the BPU to be appropriate.

5 Reflects the lag from the midpoint of the 182.5-day service period (365 / 2 / 2).

D. Credit Facility Costs

Q. Please explain your recommended adjustment relating to the Company's rate base claim for credit facility costs.

A. ACE is requesting recovery of costs relating to a PHI credit facility. The Company's claim includes annual recurring maintenance costs associated with the credit facility, as well as amortization of closing or start-up credit costs. In addition, ACE is requesting that the average balance of unamortized costs be included in rate base and that shareholders be permitted to earn a return on this balance at the Company's overall cost of capital.

As discussed later in this testimony, I am recommending that credit facility costs be excluded from the Company's revenue requirement unless the BPU includes short-term debt in the Company's capital structure, or unless ratepayers receive other commensurate benefits of this lower cost financing. However, even if the BPU were to include costs relating to the credit facility in the Company's revenue requirement, it does not follow that the unamortized balance should be included in rate base. Permitting these costs to be included in rate base would require ratepayers to pay not only a return on these costs, but also income taxes associated with this return. If the BPU finds that credit facility costs should be recovered from New Jersey ratepayers, the Company would be fully compensated for these associated start-up costs through the amortization expense that would be reflected in rates. Moreover, to my knowledge, the BPU does not have a general policy of routinely including unamortized balances in rate base. Therefore, at Schedule ACC-8, I have made an adjustment to eliminate the unamortized balance of credit facility costs from the Company's rate base claim. Such costs should be excluded from rate base regardless of the regulatory treatment afforded to the expense component of credit facility costs.

E. Prepaid Pension Asset

Q. What is the prepaid pension asset?

A. As described by Mr. Ziminsky on page 16 of his Direct Testimony, a "prepaid pension asset arises when the accumulated contributions and growth in pension plan assets exceed the accumulated costs associated with pension obligations." In this case, ACE has included a "prepaid pension asset" of $41.917 million in rate base. Mr. Ziminsky claims that the prepaid pension asset represents a prepayment by shareholders and should be included in rate base so that shareholders can earn a return on these funds prior to the time that the payments are reflected in the pension expense calculation.

Mr. Ziminsky also claims that if the prepaid pension asset is not included in rate base, then the Board should not utilize the Company's Statement of Financial Accounting Standard ("SFAS") 87 pension cost for ratemaking purposes.[6] Instead, Mr. Ziminsky argues that the Company's pension cost should only reflect the Service Cost and Interest Cost components, and that the Expected Return on Plan Assets as well as the Unamortized Losses or Gains should be excluded from the Company's revenue requirement. I will discuss each of these recommendations below.

6 The Financial Accounting Standards Board has now reclassified its pronouncements into Accounting Standards Codification ("ASC") categories. SFAS 87 is now identified as ASC-715. In this testimony, I will continue to refer to SFAS 87.

Q. How is pension cost determined for ratemaking purposes?

A. There are two methodologies used by regulatory commissions to determine the appropriate amount of pension expense to include in utility rates. Most state regulatory commissions, including the New Jersey BPU, utilize the accrual methodology set forth in SFAS 87. This is the methodology that is required to be used for financial reporting purposes under Generally Accepted Accounting Principles ("GAAP"). This pronouncement was issued by the Financial Accounting Standards Board ("FASB") in December 1985. This methodology requires a company to accrue pension costs over the working life of the employee.

Under SFAS 87, each year, a company's annual pension cost is calculated. This calculation determines the amount of pension cost that must be recognized for financial reporting purposes, based on numerous factors. The calculation considers the accumulated amount that should have been accrued at the present time based on the demographics of a company's employees, the age at which such employees are likely to retire, the expected future return on pension plan assets, assumptions regarding future payroll levels, assumptions regarding an appropriate discount rate, and other factors. When calculating the annual pension cost, certain gains and losses are amortized over a multi-year period. This amortization helps to mitigate significant fluctuations that can occur from year-to-year in pension plan earnings.

Thus, the calculation of the pension cost is a snapshot at a point in time. It is impacted by what has happened in the past as well as what is expected to happen in the future. In addition, there is a gradual true-up of past estimates with actual results over time. Pursuant to SFAS 87, a pension cost can be either positive or negative. If it is positive, then the pension plan is under-funded at a given point in time from an actuarial perspective and additional amounts must be accrued. In that case, ratepayers are required to provide for additional recovery of costs in rates. If the pension cost is negative under SFAS 87, then the plan is over-funded at a given point in time, i.e., the accumulated annual accruals exceed the amount required pursuant to SFAS 87, and ratepayers receive a credit in cost of service due to the fact that the pension cost was higher than necessary in prior years.

Q. What is the second method used by regulatory commissions?

A. A few regulatory commissions base a company's pension expense, for ratemaking purposes, on the amount of cash contributions required to be made to the pension fund. This is also referred to as the "cash methodology" to distinguish it from the accrual methodology discussed above. The actual cash funding of the plan, i.e., the amount of cash contributions to the dedicated trust that must be made by a company, is governed by the requirements of the Employee Retirement Income Security Act ("ERISA"), the Pension Protections Act ("PPA") of 2006, and Internal Revenue Service ("IRS") regulations. The minimum pension plan contribution that must be made each year is determined pursuant to ERISA and the PPA, while the IRS determines the maximum amount of any contribution that is deductible for income tax purposes.

Q. Are you recommending any adjustment to the Company's claim relating to its prepaid pension asset?

A. Yes, I am recommending that this claim be denied. The Company's proposal to include a prepaid pension asset in rate base essentially mixes the two methodologies used by regulatory commissions to determine pension expense in rates. ACE is attempting to add a true-up for the difference between accrued pension costs and cash contributions. I have several problems with the Company's proposal, as summarized below:

- ACE largely controls the amount and timing of contributions to its pension fund;
- SFAS 87 has been adopted by this Board for the determination of pension costs and should be consistently applied.
- The Company's adjustment is retroactive in that it includes cash contributions made as far back as 1987; and
- The Company's adjustment is based on assumptions regarding amounts collected from ratepayers that may not be accurate.

Q. How does ACE control the amount and timing of contributions to its pension fund?

A. The Company has wide discretion each year as to whether or not to make a contribution to its pension fund. ACE did not make any contribution to its pension fund in six of the past twelve years.[7] While I do not have data for the entire period prior to 2005, it is likely that no pension contribution was required to be made in many, if not all, of those

7 Per the response to RCR-A-139 in Docket No. ER16030252 and the response to RCR-A-114 in the current docket.

years as well. Since 2005 actual cash contributions ranged from $15 million to $60 million. However, the range of possible contributions is extremely wide. As shown in the response to RCR-A-148, since 2001, potential contributions to the PHI Retirement Plan ranged from a required minimum contribution of $0 to a maximum tax-deductible contribution of $1.793 billion! This broad range illustrates the wide latitude given to companies by the IRS with regard to pension funding. Many factors influence a company's decision with regard to pension funding, including tax considerations, the availability of cash, and a company's financial position. Thus, ACE's funding decisions are dependent, at least in part, on its ability to manage its earnings and/or to minimize its tax expense. Ratepayers should not be penalized as a result of pension funding decisions made by Company management, especially when those decisions are based on tax avoidance policies or other motives. Rather, utility rates should be based solely on the annual cost of pension benefits approved by the BPU pursuant to FAS 87.

Q. Why do you believe that it is important to ensure consistency from case-to-case in the manner in which the Company's pension expense is determined?

A. It is the consistency of using SFAS 87 expense for ratemaking that assures that, over the life of the plan, the expenses recognized pursuant to SFAS 87 will equate to the contributions made to the pension plan. While there are different assumptions and formula used to determine a Company's SFAS 87 expense and its required pension plan contributions, over the life of the plan the goal of both methodologies is the same, i.e., to recognize the Company's liability with regard to pension costs and to ensure that these costs are properly funded. If a hybrid approach is now adopted, i.e., using SFAS 87 to determine pension expense but also requiring ratepayers to pay a return on contributions to the plan, then ratepayers will be penalized by paying twice.

Q. Why do you believe that the Company's prepaid pension asset constitutes retroactive ratemaking?

A. The Company's pension asset is based on cumulative activity beginning with the adoption of SFAS 87, over thirty years ago. In the past, the BPU has never approved inclusion of a pension asset in rate base. Nor has the BPU ever approved a true-up mechanism to track actual SFAS 87 costs, or amounts collected in rates, and cash contributions. Therefore, the Company is requesting inclusion of an asset based on SFAS 87 costs and funding decisions that occurred, in many cases, well before the beginning of the Test Year in this case. Accordingly, even if the BPU believed that the Company's claim was appropriate conceptually, which it clearly is not, it would be retroactive ratemaking to permit ACE to include any differences between SFAS 87 pension cost and pension fund contributions that occurred almost thirty years ago, well before the BPU would have granted the requested ratemaking treatment. When SFAS 87 was first adopted, many companies found themselves with pension funds that were over-funded relative to the pension costs incurred for financial reporting purposes. It is only over the past few years, as stock market returns have become more volatile and as pension funding mandates have been tightened, that companies have found it necessary to make large cash contributions to their pension funds. In fact, many companies did not make any cash contributions to the fund for many years after the adoption of SFAS 87. Thus, these companies would have been required to include a reduction to rate base under the Company's proposed methodology. I am not aware of any company that proposed such a rate base reduction relating to the over-funding of pension plans during this period. It is only now, given the requirement to make cash contributions, that companies have suddenly decided that a rate base adjustment is appropriate.

Q. Is it possible to accurately quantify the amounts paid by ratepayers relating to pension costs since FAS 87 was adopted?

A. No, it is not. The Company acknowledged in the response to RCR-A-152 that it "does not 'ear-mark' individual expense areas that are authorized and/or included in revenue requirement as the stipulations of settlement in its rate case filings are silent on the amount of these costs in the approved revenue requirement." It is my understanding that most, if not all, of the Company's rate cases since SFAS 87 was adopted have been settled cases. I am not aware of any of these stipulations that specifies the amount of pension costs being recovered from ratepayers. Nor am I aware of any mechanism to track amounts actually recovered from ratepayers relating to pension costs. Therefore, even if an amount had been specified, which it was not, there is no mechanism to true-up the pension expense included in the cost of service with amounts actually recovered from ratepayers.

Q. When was the first case in which the Company requested authorization to include a

pension asset in rate base?

A. ACE first requested the inclusion of a pension asset in rate base in BPU Docket No. ER11080469. It is interesting to note that prior to 2005, ACE did not have a pension asset but instead had a pension liability, i.e., its pension plan asset balance was less than the pension obligations' accumulated expense. During this time, ACE did not include a pension liability in rate base, i.e., it did not offer to include a rate base reduction during the period that it made no contributions and recorded a pension liability. Ratepayers should not be faced with these higher rates because of discretionary funding decisions made by the Company, especially when ratepayers are also required to pay for the Company's actual pension costs based on the actuarial methodology adopted pursuant to SFAS 87.

Q. Has the BPU ever approved the inclusion of a pension asset in rate base?

A. No, to my knowledge, the BPU have never included a pension asset in rate base for any utility in New Jersey. Thus, the Company's request is unprecedented in this state, and would result in significantly higher rates for New Jersey ratepayers.

Q. Is the pension asset proposed by the Company solely related to cash contributions that ACE has made?

A. No, it is not. The pension asset is based on the pension fund balance, which includes both the return on investments earned by the pension fund as well as contributions to the fund. Thus, a prepaid pension asset can exist even if a utility does not actually make cash contributions to the plan. This is because in some years the actual market returns exceeded the returns assumed for funding purposes. Therefore, it is important to recognize that much of the prepaid pension asset can be the result of better-than-expected market returns, and not the result of cash outlays by the utility. Thus, the pension asset has not been funded solely by investors, but instead has been funded in part by market returns. Moreover, it is important to recognize that ratepayers are responsible for paying rates that include pension costs even in the event of market losses. For example, if the Company invests $60 million in the market, and loses the $60 million due to declines in the market, those losses will ultimately be passed through to ratepayers in higher pension costs through the SFAS 87 accrual methodology. Therefore, ratepayers have no guarantee that the amounts actually contributed by the Company will be available to offset pension costs in the future. This is another reason why it is important to separate the calculation of the Company's annual pension cost, which is funded by ratepayers in annual rates, from the pension asset, which does not necessarily represent amounts contributed by investors and which is not guaranteed to be available to offset future pension costs to ratepayers.

Q. What do you recommend?

A. I recommend that the BPU continue to base the Company's annual pension cost, for ratemaking purposes, solely on the expense determined pursuant to SFAS 87. I recommend that the Company's proposal for a hybrid approach, which would include a pension asset in rate base, be denied. At Schedule ACC-9, I have made an adjustment to eliminate the prepaid pension asset from rate base.

Q. Turning to Mr. Ziminsky's second adjustment, if the BPU denies the Company's request to include the pension asset in rate base, should it also modify the FAS 87 formula to exclude the expected return on plan assets?

A. No, it should not. If the BPU decides to reconsider whether or not it should determine pension costs based on SFAS 87, Rate Counsel would be happy to have that dialogue and contribute to that discussion. There may in fact be a better way to determine annual pension expense for ratemaking purposes. But as long as the BPU is using SFAS 87 for ratemaking purposes, then the Board should not unilaterally change the SFAS 87 pension cost formula. Moreover, as previously stated, ignoring the expected return on plan assets when calculating the SFAS 87 pension cost would ignore the fact that ultimately contributions to the plan and market earnings are expected to equal total pension costs during the life of the plan. Thus, over time, the SFAS 87 cost will fully compensate the Company for its pension costs. If the BPU decides to modify the FAS 87 formula, it would be very difficult for any party to keep track of how much was actually paid by ratepayers and whether ratepayers have in fact paid their fair share, or overpaid. In addition, since a portion of the Company's annual pension costs is capitalized, modifying the SFAS 87 formula would also require "unwinding" amounts that have been capitalized and reflected in utility plant-in-service. Thus, as long as the BPU has a policy of using SFAS 87 to determine pension cost, it should not unilaterally revise the pension cost formula required pursuant to SFAS 87.

F. **Storm Restoration Costs**

Q. How did the Company develop its claim associated with major storms in this case?

A. In its filing, ACE included costs related to two new storms, one of which occurred in January 2017 and one of which occurred in June 2016. In both cases, the Company proposed in its testimony to remove the actual Test Year costs, to amortize the costs over a three-year period, and to include the unamortized balance in rate base. In addition, the Company made a third adjustment to reflect a three-year amortization of costs associated with the Bow Echo Event and with Storm Jonas. This amortization was authorized pursuant to the Stipulation in Docket No. ER16030252. However, the Stipulation in that case precluded the Company from including the unamortized balance in rate base and ACE did not include the unamortized costs associated with the Bow Echo Event or Storm Jonas in its rate base claim.

Q. Are you recommending any rate base adjustments relating to the Company's claim for storm restoration costs?

A. Yes, I am recommending two rate base adjustments. Specifically, I am recommending that the unamortized balance associated with both storms be removed from rate base. ACE's investors are benefitting from the opportunity to recover these past costs through an amortization that will be included in rates over the next three years. However, they should not be permitted to earn a "profit" on storm restoration costs. Shareholders are awarded a risk-adjusted return on equity because they are expected to incur some risk.

Allowing shareholders to amortize prior storm restoration costs, and to earn a return on the unamortized balance, eliminates all such risk for shareholders and instead transfers it to the Company's regulated ratepayers. Allowing the Company to recover storm restoration costs over three years while denying the Company's claim to include the unamortized balance in rate base provides a good balance between ratepayers and shareholders. This adjustment is also consistent with the treatment agreed to by the parties in the Stipulation in the Company's last base rate case. My adjustment to exclude the January 2017 storm costs from rate base is shown in Schedule ACC-10. My adjustment to exclude the June 2016 storm costs from rate base is shown in Schedule ACC-11.

G. <u>Costs to Achieve</u>

Q. Please describe the Company's claim for costs to achieve.

A. In its filing, ACE included in rate base a regulatory asset associated with costs to achieve the merger between PHI and Exelon Corporation. The costs relate primarily to severance costs, system integration costs, and allocated Service Company costs resulting from the merger. The Company is projecting total costs to achieve of $12.305 million, which includes $7.265 million of costs incurred prior to the Test Year. ACE is seeking to include these costs in rate base, net of deferred income taxes, resulting in a rate base adjustment of $6.639 million. ACE did not include any amortization expense associated with recovery of the costs to achieve, but indicated that in its next base rate case, it would request authorization to amortize costs to achieve over a five-year period.

Q. What do you recommend?

A. I recommend that the Company's claim related to costs to achieve be denied, for several reasons. First, the majority of the costs to achieve were incurred prior to the Test Year in this case. While the Stipulation in the Company's last rate case deferred the issue of the regulatory asset to this case, the Company has not demonstrated that the level of merger savings realized to date justifies ratepayer funding of the costs to achieve. Second, it was the Company's shareholders, and not its ratepayers, who promoted the merger and stood to gain the most from the transaction. Any costs associated with that transaction should therefore be paid by those shareholders. Third, and perhaps most importantly, the costs to achieve have already been expensed on the Company's books and records of account, according to the responses to RCR-A-97 and RCR-A-98. Therefore, ACE has already written these costs off its books and records of account. Given the significant ACE rate increases that ratepayers have experienced over the past several years, and the increase that they are likely to experience in this case, it would be particularly inappropriate to require them to compensate shareholders for merger costs that benefited those shareholders and that have already been reflected in the Company's financial statements. Therefore, I have eliminated the Company's rate base claim associated with the unamortized balance of the costs to achieve. My adjustment is shown in Schedule ACC-12.

H. OPEB Liability

Q. Please describe the OPEB liability that the Company has reflected as a rate base reduction.

A. Presumably in an effort to make its prepaid pension asset more palatable, ACE has included an adjustment to reduce rate base by the amount by which accumulated OPEB costs exceed the associated contributions and market returns. In this case, the accumulated liability is greater than the contributions and market returns, resulting in a rate base reduction. This adjustment can be thought of as the mirror image of the prepaid pension asset adjustment discussed above.

Q. What do you recommend?

A. For ratemaking purposes, OPEB costs, like pension costs, are based on actuarial formulas that attempt to recover these costs over the working lives of the employees. The BPU has used the actuarial method for recovery of OPEB costs since it adopted SFAS 106 for ratemaking purposes. Similar to the discussion above with regard to pension costs, the actual cash outlay associated with OPEBs can vary each year from the cost recognized for ratemaking purposes. Consistent with my recommendation that the BPU continue to utilize the actuarial methodology for pension costs and reject the Company's claim to include the prepaid pension asset in rate base, I am making a similar recommendation with regard to OPEB costs. Although ratepayers would benefit from the inclusion of the OPEB liability in rate base, I do not believe it is appropriate to consider the cash implications for ratemaking purposes, given the fact that the BPU has adopted an accrual methodology, given the flexibility that utilities have with regard to funding, and given the impact of market returns on the calculation of the OPEB liability. Therefore, at Schedule ACC-13, I have made an adjustment to eliminate the OPEB liability from the Company's rate base claim.

I. Consolidated Income Taxes

Q. **Does ACE file its income taxes as part of a consolidated income tax group?**

A. Yes, it does. In the past, ACE filed its income taxes as part of a consolidated income tax group that included PHI and all of its subsidiaries. With the recent merger, the consolidated income tax group expanded to include all of the Exelon subsidiaries as well. By filing a consolidated return, the tax loss benefits generated by one group member can be shared by the other consolidated group members, resulting in a reduction in the effective federal income tax rate. ACE has been a member of a consolidated income tax group since at least 1991, although the various members of that group have changed with the merger of ACE and Delmarva Power and Light Company, with the eventual purchase of both companies by PHI, and now with the merger of PHI and Exelon Corporation.

Q. Has the BPU traditionally flowed through the benefits of filing a consolidated income tax return to New Jersey ratepayers?

A. Yes, it has. The BPU has traditionally flowed these benefits through to ratepayers. The issue of consolidated income tax adjustments has been thoroughly reviewed by both the Board and the New Jersey courts, both of whom have found that a consolidated income tax adjustment is appropriate.[8] In its Decision in the 1991 Jersey Central Power and Light Company ("JCP&L") base rate case (BPU Docket No. ER91121820J), dated June 15, 1993, at pages 7-8, the BPU held that:

> The Board believes that it is appropriate to reflect a consolidated tax savings adjustment where, as here, there has been a tax savings as a result of filing a consolidated tax return. Income from utility operations provides the ability to produce tax savings for the entire GPU system because utility income is offset by the annual losses of the other subsidiaries. Therefore, the ratepayers who produce the income that provides the tax benefits should share in those benefits. The Appellate Division has repeatedly affirmed the Board's policy of requiring utility rates to reflect consolidated tax savings and the IRS has acknowledged that consolidated tax adjustments can be made and there are no regulations which prohibit such an adjustment.

In the Board's Final Order, dated May 14, 2004, in the 2002 JCP&L base rate case, Docket No. ER02080506, page 45, it stated:

> As a result of making a consolidated tax filing during the years 1991-1999, GPU, JCP&L's parent company during that time period, as a whole paid less federal income taxes than it would have if each subsidiary filed separately, thus producing a tax savings. The law and Board policy are well-settled that consolidated tax savings are to be shared with customers.

The reality is that PHI, and now Exelon, has elected to file a consolidated income tax return for its subsidiaries, including ACE. Moreover, ACE has been a member of a consolidated income tax group since the Board first adopted consolidated income tax adjustments. Apparently, the filing of a consolidated tax return still offers advantages to ACE and members of the consolidated income tax group. Because the holding company

8 I am not an attorney and therefore my comments are limited to the ratemaking implications of these findings. I am not testifying on any underlying legal issues associated with consolidated income tax adjustments.

has elected to file a consolidated tax return for its member companies, including ACE, I believe it is a settled matter that the tax savings should be shared with utility ratepayers.

Q. Why should these tax benefits be flowed through to the Company's ratepayers?

A. These tax benefits should be flowed through to ratepayers because these benefits reflect the actual taxes paid. Establishing a revenue requirement based on a stand-alone federal income tax methodology would overstate the Company's tax expense, result in a windfall to shareholders, and result in rates that are higher than necessary.

Q. How does Exelon determine the actual amount of taxes paid by ACE to its parent each year?

A. The payment of taxes is governed by a Tax Sharing Agreement among the members of the consolidated income tax group. Pursuant to the agreement, ACE, and other subsidiaries with positive taxable income, pay the amount of their stand-alone tax liability to Exelon Corporation.[9] Exelon Corporation then pays the amount of taxes due by the consolidated group to the IRS. Any excess funds are then allocated by Exelon Corporation to the members of the consolidated income tax group with tax losses, resulting in a contractual means to have the regulated and profitable subsidiaries subsidize unregulated and unprofitable ventures. These procedures transfer the excess amounts collected from ratepayers for income tax expense from the utility to the affiliates

9 In response to RCR-A-103, the Company provided two tax sharing agreements, one for the PHI companies and one for the Exelon companies.

that generated the income tax losses, effectively resulting in a subsidization of the unregulated affiliates, and other unprofitable companies, by New Jersey ratepayers. In contrast, the consolidated income tax adjustment adopted by the BPU partially compensates ratepayers for this subsidization, by crediting ratepayers with carrying costs on these funds.

Q. How has the BPU traditionally calculated the consolidated income tax benefit for ratemaking purposes?

A. The BPU's policy was established in a proceeding involving Rockland Electric Company, BPU Docket No. ER02100724, Order dated April 20, 2004. In that proceeding, the BPU calculated a consolidated income tax adjustment by allocating tax losses generated by companies with cumulative tax losses to all members of the consolidated income tax group that had cumulative positive taxable income. Pursuant to the BPU's methodology employed in that case, the first step is to determine if each company included in the consolidated group had cumulative taxable income or a cumulative tax loss for the period 1991 to the present, which I will refer to as the Review Period. This analysis results in two groups of companies, those with cumulative taxable income over the Review Period and those with cumulative tax losses.

The second step is to calculate the tax loss, by year, for those companies that had a cumulative tax loss for the Review Period. The tax loss for each company in the group is then accumulated, by year, in order to determine the total annual loss for the consolidated group by year. The total annual loss, by year, is then multiplied by that year's annual federal income tax rate, in order to determine the tax loss benefit for the consolidated group by year. Adjustments are also made to reflect any alternative minimum tax ("AMT") payments made by the group. The annual tax loss benefits, net of AMT, are then accumulated for the entire Review Period, to determine the total tax loss benefit that is subject to allocation.

In step three, the accumulated tax loss benefit is then allocated to each company that had positive taxable income on a cumulative basis during the Review Period. The accumulated tax loss benefit is allocated based on the percentage share of each entity's positive taxable income to the total accumulated positive taxable income of the group.

Q. Did the BPU later initiate a generic proceeding to investigate the issue of consolidated income tax adjustments?

A. Yes, it did. The BPU issued an Order on January 23, 2013 in BPU Docket No. EO12121072, establishing a generic proceeding on the issue of consolidated income taxes. After comments from various parties, the BPU issued an Order on October 22, 2014 adopting certain modifications proposed by Board Staff. On December 17, 2014, the BPU issued a corrected order (BPU CTA Order) which reflected the earlier October 22, 2014 findings and revised an incorrect docket number in the original Order.

The revisions recommended by Staff and adopted by the BPU included:

- A limited time period of five years over which the consolidated tax adjustment would be calculated,
- The savings allocated to the New Jersey utility would be further allocated, such

that ratepayers received only 25% of the utility's share of the consolidated income tax benefit, and

- Transmission assets would not be included in the allocation.

Rate Counsel filed an Appeal to the BPU CTA Order on March 9, 2015. In its Appeal, Rate Counsel argued that the five-year look back period is arbitrary and has no support in the record. Rate Counsel also stated that the Board had failed to provide any factual or legal basis for allocating 75% of the utility's consolidated tax benefit to shareholders. Finally, Rate Counsel argued that transmission assets should also be included in the consolidated income tax calculation. Rate Counsel concluded that the revised methodology would eliminate any consolidated income tax adjustment for the majority of New Jersey electric and gas companies. It is my understanding that the BPU's CTA Order is still on appeal.

Q. Did ACE include a consolidated income tax adjustment in this case?

A. No, the Company did not include any consolidated income tax adjustment in this case. Mr. Ziminsky claimed on page 30 of his testimony that "the Board's approved calculation method does not result in a rate base reduction related to the CTA [consolidated tax adjustment]." The Company claims that since ACE had such high losses in at least some of the past five years, on a cumulative basis ACE had a net operating loss over this period. Since the consolidated income tax adjustment allocates tax benefits to companies with cumulative positive taxable income, ACE would not be allocated any portion of the consolidated income tax benefit under the methodology outlined in the BPU CTA Order. Hence, ACE argues that the consolidated income tax benefit is zero.

Q. Does the BPU's recent revision to the consolidated income tax calculation result in just and reasonable rates?

A. No, it does not. In fact, this case clearly illustrates the flaws inherent in the BPU CTA Order. As previously discussed, strict application of that Order would result in no consolidated income tax adjustment being allocated to New Jersey ratepayers, in spite of the fact that the consolidated income tax group paid [**BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** according to the response to RCR-A-109. At the same time, the Company has collected millions of dollars of income tax expense in its cost of service. On a pro forma basis, ACE is seeking to collect approximately $35.0 million annually in federal income taxes that will not be paid to the IRS in the near term. In fact, as shown in the response to RCR-A-112, at December 31, 2015, the consolidated income tax group had tax loss carryforwards of $870.2 million available for use in the 2016 tax return.[10] It is my understanding that both the BPU and the New Jersey Courts have stated that ratepayers should receive a portion of the consolidated income tax benefit. Yet under the BPU's recently-issued methodology, no such benefit would be allocated to New Jersey ratepayers.

10 The 2016 tax return will be filed in September, 2017.

Q. What is the second flaw that is highlighted in this case?

A. PHI recently entered into a global settlement with the IRS that resulted in a restatement of its tax liabilities for the period 2003-2011. As a result of this settlement, there were significant changes in the federal income tax liabilities as reported during this period. If the BPU limits the calculation of the consolidated income tax adjustment to only a five-year period, then the BPU will fail to take into account the full impact of this settlement on the Company's consolidated income tax benefit. This global settlement illustrates the fact that changes can and do happen in the taxable income or tax losses reported by the Company, for a variety of reasons. Not only can tax settlements or tax litigation change a company's income tax liability but provisions for carrying losses and gains forward or back to other periods can also impact the calculation. Therefore, it is important to utilize a period of time that is long-enough to capture the impact of these changes in taxable income or losses.

Q. What do you recommend?

A. I have recalculated the Company's consolidated income tax adjustment, based on a period of twenty years. This is the period during which tax losses can be carried forward. In addition, I have not further allocated any of the utility's share of the consolidated income tax benefit to shareholders. Shareholders are already receiving all such benefits that would otherwise be allocated to unregulated entities and/or to utilities in states that do not recognize a consolidated income tax adjustment for ratemaking purposes. Based on my recommended methodology, only 20.67% of the consolidated income tax benefit is allocated to New Jersey ratepayers. Finally, I have not excluded transmission assets from the calculation. As noted in Rate Counsel's comments on Appeal, excluding transmission assets from the calculation would prevent ratepayers from receiving the tax benefit that accrued from ratepayer funds. In addition, it treats the New Jersey electric utilities differently from the other utilities in the state. Therefore, I have not excluded transmission assets from the calculation of my consolidated income tax adjustment.

Q. What is the result of your recommended consolidated income tax calculation?

A. My consolidated income tax adjustment results in a rate base deduction of $154.546 million, as shown in Schedule ACC-14.

J. Summary of Rate Base Issues

Q. What is the impact of all of your rate base adjustments?

A. My recommended adjustments reduce the Company's rate base from $1,370.621 million, as reflected in its filing, to $1,103.757 million, as summarized on Schedule ACC-3.

VI. OPERATING INCOME ISSUES

A. Pro Forma Revenues

Q. How did the Company determine its claim for pro forma operating revenues?

A. ACE began with its estimated Test Year revenues. The Company then normalized its revenues for normal weather, annualized revenues for changes in the number of customers at the end of the Test Year, included adjustments for customer growth and changes in usage through January 31, 2018, and made an additional revenue adjustment for revenue changes through the end of 2018, which the Company termed the rate-effective period.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending four adjustments, relating to weather normalization, changes in customers and usage through January 31, 2018, and adjustments in the rate effective period.

Q. How did the Company determine its weather normalization adjustment in this case?

A. The Company utilized a 20-year period to determine normal weather in calculating its pro forma weather-normalized revenue.

Q Do you agree with the use of 20 years to weather normalize sales?

A. No, I do not. Instead, I recommend that the BPU utilize a 30-year standard for normal weather.

Q. Why do you believe that 30-year data is more appropriate to utilize in developing the Company's weather normalization adjustment than the 20-year period recommended by the Company?

A. The 30-year normal has been established by the National Oceanic and Atmospheric Administration ("NOAA"), the government organization charged with establishing and recording the climatic conditions of the United States. The 30-year standard is the objective standard, established by the government body responsible for determining normal weather conditions. Moreover, the 30-year standard is the international standard adopted by the United Nation's World Meteorological Organization ("WMO"). The 30-year normal is used for a wide range of applications and it has served as the standard in utility regulation for some time.

Q. Do you believe that the use of a NOAA standard is preferable to having regulatory commissions set their own standards?

A. Yes, I do. It should not be the role of each regulatory commission to determine "normal" weather. Rather, that determination should be made by the governmental agency and other international bodies with expertise and responsibility for tracking, analyzing, and reporting weather statistics. In the United States, that agency is NOAA, which has determined that normal weather should be defined as the arithmetic mean computed over a 30-year period of time. NOAA has further defined the appropriate time period over which to calculate normal weather as three consecutive decades.

Q. Why are longer time periods preferable to shorter ones for weather normalization data?

A. There are a few reasons. First, longer time periods tend to average out weather and temperature extremes much better than shorter periods. Obviously, one particularly cold or warm year with many or few heating/cooling degree days has a much greater effect upon a 20-year average than it does upon a 30-year average. In fact, a single data point has a 5% impact on a 20-year average, but only a 3.3% impact on a 30-year average. Therefore, the effect of a single data point is 50% greater with a 20-year average than with a 30-year average.

Second, a shorter time period may fail to include extreme weather in computing average degree days. It is normal and customary to have a very cold or a very warm year every so often, and the data base should include these extremes.

Q. Why is it important to have good standard weather data?

A. Utility rates are based upon normal operating conditions. If revenues are based on an accurate, consistent and widely-accepted standard for normalizing weather, in some years the Company's revenues will be less than normal, in some years the Company's revenues will be greater than normal, but over time, the Company's revenues will reflect normal weather and the Company will receive the opportunity to earn its fair rate of return. In addition, the use of an accepted objective standard, such as the 30-year NOAA standard, ensures consistency from case to case.

Q. Are there other factors that lead you to favor the 30-year NOAA standard over the 20 years of data recommended by the Company?

A. Yes. Among other things, the NOAA standard has a long history of use and acceptance. The use of the NOAA thirty years as "normal" is based upon an international agreement and is commonly used to reflect normal weather conditions in a variety of industries and applications.

Q. Is there a statistical reason why a 30-year normal should be used?

A. Yes, there is. The use of 30 data points has its basis in the central limit theorem, which states that if the sample size has at least 30 data points, then the distribution of sample means is normal, resulting in a normal distribution centered around the mean with a standard deviation that decreases as the sample size increases.

Q. Is the purpose of a weather normalization adjustment to predict future weather, as has sometimes been suggested?

A. No, it is not. The purpose of a weather normalization adjustment is not to forecast or predict weather for a particular year. Regulatory commissions are regulators, not weather forecasters. The purpose of a weather normalization adjustment is instead to determine what customer usage would be, assuming "normal" weather. Thus, finding that the use of a 20-year normal is a better predictor of the weather does not provide any meaningful information about normal weather on which utility rates should be based.

The regulator is attempting to determine, on a prospective basis, what a "normal" period of operating results will be. One of the components of this determination is normal weather. The regulator is not trying to predict weather, or to make a company indifferent to weather, but rather to set rates prospectively that are normalized for weather. In some years a utility will have colder than normal weather and in some years it will have warmer than normal weather. But over time, these variations constitute normal weather.

Q. Why is it important to have a consistent standard determined by an independent objective organization like NOAA?

A. The 30-year period for determining what constitutes normal weather was not defined by ACE, or Staff, or Rate Counsel. Rather, it was defined by the United States Government organization that is responsible for defining normal weather, i.e., NOAA. If an objective standard is not used, then all parties have an incentive to promote the time period that results in the best result for their particular constituency in each particular case. Deviating from the objective standard as determined by NOAA will open the door to arguments in every case about how long a period of time should determine what constitutes normal weather.

Q. Isn't it possible that weather patterns do change over time?

A. Yes, it is. However, permanent changes in weather patterns are likely to take place over a long period of time. NOAA has determined that data from a period of 30 years satisfactorily represents normal weather. To the extent weather patterns do exhibit a permanent change over time, such changes will be reflected in the 30-year NOAA data. Moreover, the BPU should not confuse the determination of "normal" weather with the issue of how customers will react to variations from normal weather. The fact that energy prices have risen, that there is better communication with customers, and that energy efficiency incentives are offered have no impact on the weather, or on the definition of normal weather. Rather, these factors impact how customers may respond to deviations from normal weather. Weather is based on climatological patterns and customers have virtually no impact on these weather patterns, at least not over the 30-year period that is defined as constituting normal weather.

However, the BPU should be mindful of the difference between changes in weather patterns over time and changes in usage patterns over time. The two are not the same. While NOAA uses a 30-year period to determine normal degree days, NOAA is not involved in forecasting how energy sales are likely to be impacted due to variations in degree days. Due to conservation efforts, more efficient appliances and furnaces, and other factors, it is entirely possible that the impact of variations in degree days is different in 2017 than it was in 1987. My recommendation that the BPU continue to utilize a 30-year standard does not prevent the utility or other parties from presenting arguments regarding the *impact* of weather variations on energy usage. By continuing to utilize a thirty-year weather standard, the BPU is not precluding any party from providing evidence demonstrating the impact of various weather changes on electricity or natural gas usage in a utility base rate case.

Q. How did you quantify your adjustment?

A. In its filing, the Company's weather normalization adjustment decreased operating revenue at present rates by $3,730,274. In response to RCR-A-4, the Company indicated that the use of a 30-year normal would have decreased revenue at present rates by $4,121,034. Therefore, the use of the 30-year normal will actually decrease the Company's pro forma revenue at present rates by $390,760, resulting in a slightly higher revenue increase. At Schedule ACC-16, I have made an adjustment to reflect a weather normalization adjustment based on the use of a 30-year period to determine normal weather.

Q. Please explain your revenue adjustment relating to changes in customers and usage through January 31, 2018.

A. In its filing, ACE included an adjustment to reflect changes in customer counts and usage per customer through January 31, 2018. These adjustments were intended to correspond with that portion of its post-test year adjustment that included plant additions through January 31, 2018 in rate base.

With regard to customers, ACE projected growth in residential customers through January 31, 2018, but projected declines in commercial and streetlighting customers. The net result was a projected revenue decrease of $355,089. With regard to usage, ACE projected increased consumption per customer for all classes except residential. The Company projected a 1.76% decline in residential consumption from the end of the Test

Year through January 31, 2018, resulting in an overall reduction of revenues of $665,943.

Since I am recommending that post-test year plant additions be excluded from rate base, it is necessary to make a corresponding adjustment to eliminate customer growth after the end of the Test Year. Therefore, at Schedule ACC-17, I have made an adjustment to eliminate the Company's revenue adjustment relating to the change in the number of customers through January 31, 2018. At Schedule ACC-17, I have also eliminated the Company's adjustment relating to changes in consumption through that date. These changes are entirely speculative and do not meet the known and measurable standard of the Elizabethtown Order cited earlier.

Q. What is the last revenue adjustment that you are recommending in this case?

A. The Company has also included an adjustment to reflect a net loss of revenues during the rate-effective period, i.e., February 1, 2018 through December 31, 2018. This adjustment was based on annualized customer and usage growth of $2,444,892, offset by reductions due to a) loss of casino load, b) the impact of energy efficiency and demand side management projects, and c) the impact of distributed generation. I am recommending that this adjustment be rejected, for two reasons. First, the adjustment is entirely speculative and does not meet the known and measurable standard for post-test year adjustments. Second, the adjustment reflects changes in revenues that are more than nine months beyond the end of the Test Year. Given the speculative nature of this adjustment, and the fact that it pertains to changes in customers and consumption that are more than nine months beyond the Test Year, I recommend that this adjustment be rejected, as shown in Schedule ACC-18.

B. Salary and Wage Expense

Q. How did the Company determine its salary and wage claim in this case?

A. The Company's claim is based on projected payroll costs for calendar year 2018, which ACE terms the "Rate Effective Period". The Company quantified its claim in two separate adjustments. First, ACE included an adjustment relating to salary and wage increases that will take effect within nine months of the end of the Test Year. As shown in the Company's workpapers, ACE began with its projected costs for each month of the Test Year, separately identifying union and non-union employee costs. For union employees, the Company reflected annual payroll increases of 3.0% on October 9, 2017. For non-union employees, the Company included a payroll increase of 2.37% that was effective during the Test Year (March 1, 2017), and a projected increase at March 1, 2018 of an additional 3.0%. In both cases, the Company's claim reflects these increases through December 2018. These adjustments result in an increase of $2.439 million to the Company's Test Year salary and wage expense.

Second, ACE included an additional union increase of 3.0% projected to take effect on October 9, 2018. This "Rate Effective Period" adjustment resulted in a further salary and wage increase of $201,249.

Q. Are you recommending any adjustment to the Company's claim for salaries and wages?

A. Yes, I am recommending that the BPU reject both of these adjustments, and instead determine the Company's pro forma salary and wage costs based on projected costs for the twelve months ending April 30, 2018.

Actual payroll data for the first four months of 2017 indicates that the Company's Test Year claim is overstated. Actual costs for this four-month period were $23,245,401, or $428,273 less than projected by ACE in is filing. In addition, while the Company's first payroll adjustment is limited to increases that are projected to occur within nine months of the end of the Test Year, the Company's claim includes the impact of these increases during the entire twelve-month period ending December 31, 2018, or seventeen months past the Test Year. I recommend that the Company's payroll adjustment be updated a) to reflect actual data through April 30, 2017 and b) to limit the impact of post-test year adjustments to costs through April 30, 2018, nine months past the end of the Test Year, consistent with the Elizabethtown Order. My adjustment is shown in Schedule ACC-19.

In addition, at Schedule ACC-20, I have made an adjustment to eliminate the Company's second labor cost adjustment, the "Rate Effective Period" adjustment. This adjustment reaches too far beyond the end of the Test Year and distorts the regulatory triad of synchronizing rate base, revenues, and expenses. Therefore, I recommend that the BPU reject both of the Company's salary and wage adjustments, and instead base the Company's revenue requirement on labor costs for the twelve months ending April 30, 2018.

C. Incentive Compensation Plan Expense

Q. Please describe the Company's incentive compensation program.

A. The Company has included $6.418 million of non-officer incentive compensation costs in its revenue requirement claim. The majority of these costs relate to the Company's Annual Incentive Plan ("AIP"). The AIP was revised after the merger with Exelon to conform to the incentive plans offered to other Exelon employees. The Company provided copies of several Exelon and PHI Business Unit Supplements for 2016 and 2017 in the response to RCR-A-19. Those supplements generally identify the Key Performance Indicators ("KPI") that establish the potential funding for the AIP. However, other key details of the plan were not provided, including a description of which employees are eligible for the plan and how individual awards are determined.

Q. How does the Exelon AIP compare with the prior PHI annual incentive plan?

A. Although full details were not provided, it appears that one of the key differences is that the funding pool for the Exelon AIP is not based on an earnings per share threshold, although there are other financial indicators that contribute to the funding pool, including total O&M expenses and capital expenditures. Other key performance indicators include measures related to customer service and reliability, and safety.

Q. Did the Company include executive incentive program costs in its revenue requirement claim?

A. Yes, ACE did include $2,510,805 of executive incentive program costs in its claim. In addition, the Company incurred an additional $1,808,595 of executive incentive compensation costs in the Test Year. However, these costs were excluded from the Company's claim on the basis that the benchmarks relating to these awards were largely financial.

Q. Do you believe that the incentive compensation program costs are appropriate costs to pass through to ratepayers?

A. No, I do not. I have several concerns about these types of programs. ACE employees are well compensated independent of incentive compensation awards. Non-union employees have consistently been awarded annual payroll increases of 2.5% to 3.0% and ACE is projecting that such increases will continue. Thus, there is no indication that the employees of ACE are underpaid or that the Company would have difficulty attracting qualified employees in the absence of these programs.

In addition, I have concerns about the level of incentive compensation programs, especially since the merger of PHI and Exelon Corporation. Incentive compensation awards have skyrocketed since the merger. Following are the Company's non-executive incentive compensation costs over the last several years, as provided in the response to RCR-A-19:

Year	Non-Executive Incentive Compensation
Test Year Estimate	$6,418,159
2016	$5,636,740
2015	$3,540,617
2014	$3,664,616
2013	$1,988,578
2012	$3,186,940

As shown above, incentive compensation costs increased dramatically in 2016 and 2017 relative to prior years.

Q. Are the key performance measures used to determine the funding of incentive compensation plans the types of measures that ratepayers have the right to expect?

A. Yes, they are. The funding pool is based on factors that are typically expected of a utility such as reliability, customer service, and cost control. There is nothing unusual about such measures and ratepayers have a right to expect that the utility will provide acceptable service at a reasonable cost.

Q. Does the level of service that ACE's ratepayers have received over the past few years justify incentive compensation awards?

A. No, it does not. In fact, problems with reliability and quality of service resulted in the establishment of a Reliability Improvement Program ("RIP") for ACE. While ACE's reliability has improved, and currently meets at least some of the RIP objectives, the level of service being provided does not warrant the payment of incentive compensation awards. In addition, at least some of the key performance indicators are based on commitments that were made as part of the Exelon merger. Therefore, the Company is required to meet these commitments in any case.

Finally, ACE's ratepayers have been burdened with annual rate increases, which have resulted in part from the need to improve reliability and quality of service. Moreover, the Company's operating and maintenance costs increased significantly in 2016. As shown in the response to RCR-A-1, operating and maintenance costs excluding production increased from $268.440 million in 2015 to $325.089 in 2016, an increase of 21.1%. While some of this cost increase undoubtedly related to merger activity, the fact that the Company is continuing to make annual rate filings in spite of the promise of merger savings suggests that ACE doesn't deserve to recover incentive compensation costs from already over-burdened ratepayers.

Q. Has the BPU previously addressed this issue?

A. Yes. In the 2000 Middlesex Water Company base rate case, Board Staff argued in its Initial Brief that,

> Staff is persuaded by the arguments of the RPA that, at this time, the incentive compensation expenses should be not be recovered from ratepayers. According to the record, incentive compensation expenses have tripled since 1995. In addition, the record also indicated that the bonuses are significantly impacted by the Company achieving financial performance goals. These facts lend strength to the RPA's position that it is inappropriate for
> the Company to request recovery of bonuses in rates at this time.[11]

The Administrative Law Judge ("ALJ") in that case initially recommended that Middlesex be permitted to recover 50% of its incentive compensation costs in rates.

11 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Staff Initial Brief, page 37.

However, the BPU rejected the ALJ's recommendation and instead ordered that 100% of these costs be disallowed.[12]

In an earlier decision, the BPU found that including employee incentives in utility rates is especially troublesome during difficult economic times, finding that,

> We are persuaded by the arguments of Staff and Rate Counsel that, at this time, the incentive compensation or "bonus" expenses should not be recovered from ratepayers. The current economic condition has impacted ratepayers' financial situation in numerous ways, and it is evident that many ratepayers, homeowners and businesses alike, are having difficulty paying their utility bills and otherwise remaining profitable. These circumstances, as well as the fact that the bonuses are significantly impacted by the Company achieving financial performance goals, render it inappropriate for the Company to request recovery of such bonuses in rates at this time. Especially in the current economic climate, ratepayers should not be paying additional costs to reward a select group of Company employees for performing the job they were arguably hired to perform in the first place.[13]

ACE has been filing almost annual rate cases since 2009. During this time, the Company has not only sought numerous rate increases but it has also provided annual salary increases to its employees. During this period, ratepayers have faced difficult economic conditions, compounded by several major storms that have put a significant financial burden on some residents. Thus, although the incentive awards are no longer tied directly to earnings per share thresholds, the BPU's reasoning for disallowing these costs is just as relevant today as it was in 1993.

Q. Doesn't the Company use a compensation consulting firm to benchmark its

12 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Order Adopting in Part/Modifying in Part/Rejecting in Part Initial Decision at 25-26 (June 6, 2001).

13 I/M/O the Petition of Jersey Central Power & Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions, BRC Docket No. ER91121820J, Final Decision and Order Accepting in Part and Modifying in Part the Initial Decision at 4 (June 15, 1993).

compensation?

A. Yes, it does. It is my understanding that the Company utilizes compensation consulting firms to evaluate its practices and provide information on compensation at other companies to use as a benchmark for its compensation programs. However, the use of such benchmarks has a detrimental effect on ratepayers as compensation costs spiral, especially at the executive level.

Q. Why do you believe that the use of benchmarking results in spiraling executive compensation costs?

A. Companies state that they must benchmark their compensation in order to be competitive. However, such benchmarking actually results in ever-increasing executive compensation levels. This is because companies generally target their compensation to the 50th percentile of companies in the proxy group selected for benchmarking. Such practices tend to escalate increases in compensation, especially for highly-paid officers. These studies compare the subject company's compensation to compensation in a broad range of other firms. Since most companies do not want to find themselves in the lower half of the benchmark group, companies that typically fall below the average raise their compensation – and hence the average of the benchmark companies increases. This sets off a chain of events that results in ever-increasing compensation levels as additional companies must increase their compensation levels to avoid falling below the 50th percentile. The BPU should be particularly wary of any compensation plans that utilities attempt to justify by means of comparison to benchmark studies. It is not surprising that executive compensation levels have risen dramatically over the past few years, along with the practice of benchmarking.

Q. What do you recommend?

A. I recommend that the BPU disallow 100% of the Company's claim for non-executive incentive compensation awards. The Company's employees are already well compensated and the level of service being received by New Jersey ratepayers does not justify the payment of additional incentive awards. Moreover, the level of incentive compensation awards has increased dramatically since the merger, yet employees continue to receive generous annual merit increases. My adjustment is shown in Schedule ACC-21. In addition, I recommend that 100% of the Company's claim for executive incentive compensation awards be denied. My adjustment to eliminate executive incentive compensation plan costs is shown in Schedule ACC-22.

D. Payroll Tax Expense

Q. What adjustment have you made to the Company's payroll tax expense claim?

A. Since I am recommending adjustments to the Company's claims for salaries and wages and incentive compensation costs that result in a net expense reduction, it is necessary to make a corresponding adjustment to eliminate certain payroll taxes from the Company's revenue requirement claim. At Schedule ACC-23, I have eliminated payroll taxes associated with my recommended salary and wage adjustment and with my incentive compensation plan adjustments. To quantify my adjustment, I utilized the pro forma payroll tax rate of 4.27%, which was the composite rate reflected in the Company's filing, and applied it to my recommended adjustments for salaries and wages and for incentive compensation program costs.

E. Supplemental Executive Retirement Program ("SERP") Expense

Q. What are SERP costs?

A. These costs relate to supplemental retirement benefits for key executives that are in addition to the normal retirement programs provided by the Company. These programs generally exceed various limits imposed on retirement programs by the IRS and therefore are referred to as "non-qualified" plans. In RCR-A-24, Rate Counsel asked the Company to "describe any SERP benefits". In response, ACE directed Rate Counsel to the Form 10K/A filing for the year ending December 31, 2015. As stated in that document, "[i]f a participating executive's retirement benefit under the Pepco Holding Retirement Plan is reduced by the Qualified plan limitations…" then an additional retirement benefit is paid under the SERP. The SERP will also provide additional benefits if certain bonuses or other compensation awards are not included in the calculation of benefits pursuant to the qualified plan.

Q. What are the Test Year SERP costs that the Company has included in its claim?

A. As shown in the response to RCR-A-134, the Company included SERP costs of $1,443,128 in its revenue requirement claim. The vast majority of these costs relate to costs allocated to ACE by the PHI Service Company. SERP costs that are incurred directly by ACE and a small portion of Exelon Business Service Company costs are also included in the filing.

Q. Do you believe that these costs should be included in utility rates?

A. No, I do not. The officers of the Company are already well compensated. Moreover, the officers that receive SERP benefits are also included in the normal retirement plans of the Company, so ratepayers are already paying retirement costs for these executives. If ACE wants to provide further retirement benefits to select officers and executives then shareholders, not ratepayers, should fund these excess benefits. Therefore, I recommend that the Company's claim for SERP costs be disallowed. My adjustment is shown in Schedule ACC-24.

F. <u>Medical Benefit Expense</u>

Q. How did the Company determine its medical benefits expense claim in this case?

A. ACE's claim is based on projected increases of 4.21%, 1.19%, and 8.34% for medical, dental, and vision benefit costs respectively. The Company indicated that its projections are based on a three-year average of actual cost increases.

Q. What do you recommend?

A. The increases reflected in the Company's claim are speculative and do not meet the known and measurable standard required for post-test year adjustments. This is especially true given the 2016 merger with Exelon Corporation and the resulting synergies that were expected to result from that merger, including a reduction in personnel. Given the merger, there is no reason to assume that the level of increases experienced over the past three years are representative of increases that will occur within nine months of the Test Year. Since ACE has not supported its claimed post-test year increases, I recommend that the BPU deny ACE's pro forma adjustment relating to medical benefit costs. My adjustment is shown in Schedule ACC-25.

G. <u>Rate Case Expense</u>

Q. How did the Company develop its rate case expense claim?

A. ACE's rate case expense claim is based on total estimated costs for the current case of $723,525. The Company is proposing a three-year amortization period for these costs, resulting in an annual rate case expense claim of $241,178. In addition to its claim for rate case costs, ACE has also included a normalization adjustment to normalize other regulatory costs based on a three-year average of such costs.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am recommending two adjustments. First, I believe that the Company's projected claim for rate case costs is overstated. In fact, a review of costs in the last three rate cases demonstrates that ACE's actual rate case costs have consistently been less than the costs claimed in its filings, as shown below:[14]

14 Per the response to P-AREV-34.

Case	Claimed	Actual
ER16030252	$453,950	$299,405
ER14030245	$508,950	$125,670
ER12121071	$506,100	$246,099

I am recommending that the average of the actual costs incurred in the last three base rate case filings be utilized as the pro forma rate case costs in this case. This recommendation results in a pro forma cost of $223,725 for the current case, as shown in Schedule ACC-26.

In addition, the BPU has a long-standing policy of requiring a 50/50 sharing of rate case costs between shareholders and ratepayers. This policy is based on the assumption that base rate case filings provide benefits to both shareholders and ratepayers, and therefore should be allocated equally between the two groups. The Company has not reflected any sharing of rate case costs in its filing. Accordingly, at Schedule ACC-26, I have also made an adjustment to allocate 50% of the Company's pro forma case costs to shareholders. To quantify my adjustment, I accepted the three-year amortization period for rate case costs proposed by ACE in its filing.

H. <u>Injuries and Damages Expense</u>

Q. How did ACE determine its claim for injuries and damages expenses in this case?

A. As shown in Company Adjustment No. 16, ACE utilized a three-year average of injuries and damages expense in order to calculate its pro forma claim in this case. Specifically, ACE averaged costs for the twelve months ending July 31, 2015, twelve months ending July 31, 2016, and estimated for the twelve months ending July 31, 2017. The Company utilized a three-year average because injuries and damages expense tends to fluctuate from year-to-year. Therefore, ACE attempted to normalize these costs by use of a three-year average.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes. Given the fluctuating nature of injuries and damages costs, I am not opposed to the use of a multi-year average in order to develop a normalized level of such costs to include in rates. However, a review of historic data indicates that the actual costs incurred during the twelve months ending July 31, 2015 were significantly higher than costs incurred in the other two years, as shown below:

12 Months Ending July 2015	$4,100,870
12 Months Ending July 2016	$574,783
Est. 12 Months Ending July 2017	($652,660)

In fact, the costs incurred for the twelve months ending July 31, 2015 are so much higher, than I do not believe that a three-year average provides a reasonable normalized level of future costs.

Q. What do you recommend?

A. Given that the twelve months ending July 31, 2015 is a significant outlier, the Board could either eliminate these costs altogether from the three-year average or it could utilize a longer period over which to average the costs for injuries and damages expense. I am recommending the latter approach. Therefore, at Schedule ACC-27, I have made an adjustment to reflect a five-year average for injuries and damages expense. The use of a five-year average mitigates the impact of the unusual activity during the twelve months ending July 31, 2015 while still recognizing that extreme activity can occur periodically.

I. Credit Facilities Expense

Q. Has ACE requested recovery of costs associated with a PHI credit facility?

A. Yes, it has. In its filing, ACE included a rate base adjustment of $568,524 and an operating expense claim of $654,783 relating to a short-term credit facility operated by PHI.

Q. Are you recommending any adjustment relating to the Company's claim for credit facility costs?

A. Yes, I am. My recommended adjustment to the Company's rate base claim was discussed previously in the Rate Base section of this testimony. With regard to operating expenses, I am similarly recommending that these costs be disallowed.

Q. What is the basis for your adjustment?

A. Ratepayers are not benefitting from this low-cost credit facility and therefore I recommend that the associated costs be disallowed. Neither the Company nor Mr. Kahal have included the short-term debt provided by this credit facility in their recommended capital structures in this case. Moreover, the Company has argued in the past that the credit facility benefits ratepayers because it provides a source of short-term debt which is reflected in the AFUDC rate, thereby resulting in a lower AFUDC accrual and a corresponding lower rate base. However, as shown in the response to P-AREV-68, the AFUDC rate utilized in the Test Year was very high, and was actually higher than the cost of capital being recommended by Mr. Kahal in this case.

If short-term debt is not included in the Company's capital structure, or is not reflected in the AFUDC rate, then ratepayers should not be required to pay for a short-term credit facility that is not providing them with any resulting benefit. The Company cannot have it both ways, i.e., exclude short-term debt from the capital structure and from AFUDC but include the cost of the credit facility in its revenue requirement. Accordingly, unless the BPU reflects short-term debt in the capital structure, or adjusts rate base to reflect a lower AFUDC rate, then it should make an adjustment to exclude all credit facility costs from the Company's revenue requirement.

Q. Doesn't this credit facility finance the Company's cash working capital requirement and allow the Company to borrow in the commercial paper market?

A. Yes, it does. As noted on page 27 of Mr. Ziminsky's testimony, "[t]his $1.5 billion credit facility is vital to the day-to-day working capital needs of the Company and is a requirement by the various rating agencies to maintain ACE's separate corporate credit rating." However, the Company's working capital requirement, including its cash working capital requirement, is already included in rate base. Investors are already being compensated for the financing of working capital. In addition, they are being compensated for such financing at the overall weighted average cost of capital, even though the actual short-term financing cost is significantly lower.

Mr. Ziminsky goes on to state that "[t]his credit facility allows the Company to borrow in the commercial paper market." However, commercial paper is not included in the Company's capital structure and was not included in the calculation of the AFUDC rate in the Test Year. While the Company is borrowing commercial paper at low short-term debt rates, this low-cost debt is not reflected in the weighted average cost of capital being claimed by either the Company or Rate Counsel. Since ratepayers are not getting the benefit of this lower-cost debt, they should not have to pay the costs of the associated credit facility. Accordingly, at Schedule ACC-28, I have made an adjustment to eliminate credit facility costs from the Company's revenue requirement.

J. <u>Storm Restoration Expense</u>

Q. In addition to the rate base adjustments discussed earlier, are you recommending any adjustment to the Company's expense claim relating to storm damage expense?

A. Yes, I am recommending one adjustment. As previously discussed, in its original filing the Company stated that it was eliminating actual Test Year costs associated with two storms - one in January 2017 and one in June 2016. Instead of reflecting the actual Test Year costs for these storms, the Company indicated that it was seeking a three-year amortization of the related storm restoration costs.

With regard to the June 2016 storm, ACE did exclude the actual Test Year costs in its adjustment and the Company replaced those costs with annual amortization expense, based on a three-year amortization period. However, with regard to the January

2017 storm, ACE did not make an adjustment to eliminate the actual Test Year costs, even though it did make an adjustment to reflect the annual amortization expense, again based on a three-year amortization period. Based on my discussions with the Company, I believe that this was just an oversight on their part. Accordingly, at Schedule ACC-29, I have made an adjustment to remove the actual Test Year costs for the January 2017 storm.

K. <u>Meals and Entertainment Expense</u>

Q. Are you recommending any adjustment to the Company's meals and entertainment expense claim?

A. Yes, I am. According to the response to RCR-A-49 the Company has included in its filing approximately $258,815 of meals and entertainment expenses that are not deductible on the Company's income tax return. These are costs that the IRS has determined are not appropriate deductions for federal tax purposes. If these costs are not deemed to be reasonable business expenses by the IRS, it seems appropriate to conclude that they are not reasonable business expenses to include in a regulated utility's cost of service. Accordingly, at Schedule ACC-30, I have made an adjustment to eliminate these costs from the Company's revenue requirement.

L. <u>Industry Dues Expense</u>

Q. Are you recommending any adjustment to the Company's claim for membership dues?

A. Yes, I am. In response to RCR-A-45, the Company indicated that $565,626 of industry dues was included in its filing. This included payments to the New Jersey Conference of Mayors, various Chambers of Commerce, the New Jersey Business and Industry Association, as well as dues to the Edison Electric Institute ("EEI") and the Electric Power Research Institute ("EPRI").

Q. Are you recommending any adjustment to the industry dues included by the Company in its filing?

A. Yes, I am recommending that 20% of industry dues be disallowed. Many of the organizations included in this response engage in lobbying activities, the costs of which should not be charged to ratepayers. In addition to explicit lobbying costs, most of these organizations also engage in other activities that should not be charged to ratepayers, such as public affairs, media relations, and other advocacy initiatives.

Q. Are lobbying costs an appropriate expense to include in a regulated utility's cost of service?

A. No, they are not. Lobbying expenses are not necessary for the provision of safe and adequate utility service. Ratepayers have the ability to lobby on their own through the legislative process. Moreover, lobbying activities have no functional relationship to the provision of safe and adequate regulated utility service. If the Company were to immediately cease contributing to these types of efforts, utility service would in no way be disrupted. For all these reasons, I recommend that costs associated with lobbying be disallowed.

Similarly, public affairs, media relations, and other advocacy initiatives should not be charged to ratepayers. Accordingly, I am recommending that 20% of the Company's industry dues identified in the response to RCR-A-45 be disallowed on the basis that such costs constitute lobbying activities or should not otherwise be charged to cost of service. I recognize that the specific level of lobbying/public affairs/media activity varies from organization to organization. However, based on my review of these organizations and on recommendations in other utility rate proceedings, I believe that a 20% disallowance is a reasonable overall recommendation. My adjustment is shown in Schedule ACC-31.

M. <u>Miscellaneous Expenses</u>

Q. Are you recommending any other operating expense adjustments?

A. Yes, I am recommending two miscellaneous adjustments. First, in response to P-AREV-23, the Company identified a write-off of software in the amount of $116,662 that occurred in the Test Year. This write-off was booked to FERC Account 930.2, Miscellaneous General Expense. In response to RCR-A-75, the Company indicated that these systems were written-off because the "associated Departments identified that the assets were no longer in use." Since this write-off is non-recurring, it should not be included in prospective rates. Moreover, including these costs in the Company's revenue requirement results in ratepayers paying for assets that are no longer providing them with utility service. Therefore, at Schedule ACC-32, I have made an adjustment to eliminate this write-off from ACE's revenue requirement.

Q. What is your second adjustment?

A. I am recommending that $28,795 in media costs be disallowed. These costs were identified in the response to P-AREV-36 and relate to image enhancement programs including 2016 Labor Day Print ads and other promotional material. In response to P-AREV-37, the Company provided copies of several ads and it is clear that at least some of this advertising is intended to promote ACE's corporate image, including ads regarding improvements in reliability and additional infrastructure investment. Costs for advertisements that are intended to enhance a utility's corporate image are routinely disallowed by regulators. Therefore, at Schedule ACC-32, I have also included a miscellaneous expense adjustment to remove $28,795 in media costs.

N. <u>Depreciation Expense</u>

Q. Have you made any adjustments to the Company's claim for pro forma depreciation expense?

A. Yes, since I am recommending that post-test year plant additions be excluded from rate base, it is necessary to make a corresponding adjustment to eliminate the associated depreciation expense. At Schedule ACC-33, I have made an adjustment to eliminate depreciation expense associated with the August 2017 – January 2018 plant additions that I recommend be excluded from rate base. At Schedule ACC-34, I have made a similar adjustment to eliminate depreciation expense associated with the February-March 2018 plant additions that I recommend be excluded from the Company's rate base.

O. Interest Synchronization

Q. Have you adjusted the pro forma interest expense for income tax purposes?

A. Yes, I have made this adjustment at Schedule ACC-35. It is consistent (synchronized) with my recommended rate base and with the capital structure and cost of capital recommendations of Mr. Kahal. I am recommending a lower rate base than the rate base included in the Company's filing, which results in a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under Rate Counsel's recommendations. Therefore, I have included an interest synchronization adjustment that reflects a higher pro forma income tax expense for the Company and a decrease to pro forma income at present rates.

P. Income Taxes and Revenue Multiplier

Q. What income tax factors have you used to quantify your adjustments?

A. As shown on Schedule ACC-36, I have used a composite income tax factor of 40.85%, which includes a corporate business tax rate of 9.0% and a federal income tax rate of 35%. These are the state and federal income tax rates contained in the Company's filing.

My revenue multiplier, which is shown in Schedule ACC-37, incorporates these tax rates. In addition, the revenue multiplier also includes the BPU and Rate Counsel assessments, based on rates of 0.239% and 0.05% respectively. This results in a revenue multiplier of 1.6955, which is the same revenue multiplier reflected in the Company's filing.

VII. REVENUE REQUIREMENT SUMMARY

Q. What is the result of the recommendations contained in your testimony?

A. My adjustments indicate a revenue deficiency at present rates of $5.373 million as summarized on Schedule ACC-1. This recommendation reflects revenue requirement adjustments of $64.787 million to the Company's requested revenue increase of $70.160 million.

Q. Have you quantified the revenue requirement impact of each of your recommendations?

A. Yes, at Schedule ACC-38, I have quantified the revenue requirement impact of each of the rate of return, rate base, revenue and expense recommendations contained in this testimony.

VIII. SYSTEM RENEWAL REPLACEMENT CHARGE ("SRRC")

A. Introduction

Q. Please describe the Company's proposed SRRC.

B. As discussed on page 19 of Mr. McGowan's testimony, ACE is proposing to implement a System Renewal Recovery Charge "to recover its spending on non-incremental reliability and emergency capital projects." The Company is proposing that all reliability and emergency plant additions that go into service from 2018-2021 be recoverable through this surcharge mechanism. As shown in Table 7 to Mr. Sullivan's testimony, ACE forecasts a total of $375.8 million of investment over this four-year period that would be recoverable through the SRRC.

Q. Would all capital spending be recovered through the SRRC under the Company's proposal?

A. All reliability and emergency projects would be included. The only investment that would not be included in the surcharge would be investment related to customer growth or general plant investment. ACE estimates that approximately $60 million per year of investment would not be recovered through the surcharge. However, much of this investment would be recovered from new customers for whom the investments are being made.

Q. How does the Company propose to recover the investment that is subject to the surcharge mechanism?

A. The Company is proposing to recover the investment on a contemporaneous basis. Under the Company's proposal, ACE would make a filing within 30 days of a BPU Order authorizing the tracker, identifying the projects that are expected to go into service from April 1, 2018 through March 31, 2019, and the associated cost. The surcharge would be designed to recover the revenue requirement associated with those projects during the upcoming twelve-month period. The revenue requirement would be based on the pre-tax return on net investment plus depreciation expense. The SRRC would be subject to an annual true-up, with interest. Each year, the Company would calculate the actual revenue requirement, based on the amount of investment that actually went into service during the preceding twelve months and the timing of those projects. The subsequent year's surcharge would be adjusted to recover any over/under-recovery, in addition to the projected revenue requirement for the upcoming twelve-month period.

Q. Does the Company propose an earnings test as part of the SRRC?

A. Yes, it does. The Company is proposing that if the actual return on equity exceeds the return on equity approved in the Company's last base rate case by 50 basis points, ACE will establish a regulatory liability to defer the excess earnings and to return the excess to ratepayers in a subsequent base rate case. ACE is proposing that this earnings test be done on a cumulative basis, comparing cumulative actual and authorized returns since the last base rate case.

Q. What is the rationale for the Company's proposed surcharge?

A. ACE claims that the surcharge is necessary because ACE is not otherwise able to earn its authorized rate of return, due to the use of an historic test year and regulatory lag. ACE also points out that it has made significant investments in recent years. However, the Company failed to point out that much of this investment was necessary because ACE's reliability and quality of service had deteriorated, presumably due to the lack of adequate utility investment in earlier years. Fortunately, it is my understanding that ACE's reliability has improved significantly over the past few years, due in part to the RIP that was subsequently implemented.

The Company also claims that its sales have declined over the past few years, putting further pressure on earnings. However, at least some of this decline was due to changes in the casino industry, which appears to be stabilizing. In addition, general economic conditions over the past several years have also hurt sales. However, this sales decline is not expected to be as severe in the future, as acknowledged by ACE.

B. <u>Evaluation of the SRRC</u>

Q. What factors should the BPU consider as it evaluates the Company's request for approval of a SRRC mechanism?

A. The BPU should consider whether such a mechanism is necessary in order for the Company to meet its service obligations. Over the past few years, since the adoption of the RIP, the Company has demonstrated that it is able to undertake required investment and to recover such costs through the base rate case process. In addition, the Company already has an approved PowerAhead Program to address incremental investment associated with the storm hardening of its infrastructure.

The investment proposed by ACE that would be recovered through the surcharge is not incremental investment – it is the normal, routine investment that is required in order to maintain a regulated electric utility. Moreover, reliability is not a new concept for the Company or for the BPU. Rather, insuring reliability is an integral part of managing any utility distribution system. The regulatory compact provides that in exchange for being granted a monopoly franchise area, a utility will provide safe and reliable utility service at reasonable rates. The obligation to provide safe and reliable service is a cornerstone of the utility's obligations. Thus, the concept of undertaking reliability improvements, when required, is not new or novel. Rather, this is a fundamental obligation of any electric distribution company.

Q. Has the Company's obligation with regard to reliability changed over the years?

A. No, it has not. While there may have been changes in certain regulations with regard to safety and reliability over the years, the utility has always had, and continues to have, an obligation to operate its business in a safe and reliable manner. This has not changed. While several severe weather events have caused the BPU to further examine the utility's ability to continue service in the event of a major storm, the ability to meet changing operating conditions, including possible changes in weather conditions, does not require the BPU to abandon traditional cost recovery mechanisms.

ACE has not shown why an alternative recovery mechanism is necessary in order to undertake those investments necessary to provide safe and reliable utility service. From a cost recovery prospective, investments are either necessary in order to meet the Company's service obligation or they are not. While it would be ideal to ensure a 100% reliable utility system, 100% reliability is neither possible nor is it a cost-effective goal. I will defer to Rate Counsel's other consultants to determine the level of investment necessary to ensure that the Company meets its service obligation to ratepayers. However, that level of investment should be recovered pursuant to the base rate case methodology that has traditionally been used by the Company to recover its cost of service.

Q. How does the recovery mechanism envisioned for the SRRC fundamentally differ from base rate recovery?

A. The Company's proposed SRRC is an accelerated recovery mechanism - one that will require ratepayers to pay for certain costs earlier than they would under traditional ratemaking. In addition, not only does the proposed recovery mechanism accelerate recovery of costs that would not otherwise be recoverable until the Company filed a base rate case, but the Company's proposal further accelerates recovery by requiring ratepayers to pay for not only actual expenditures, but projected expenditures as well. According to Mr. McGowan's testimony, the annual surcharge would be based on forecasted investment each year, so ratepayers would be required to begin to pay for plant that was not yet in-service and which will not be in-service until several months into the future, if at all. Even though this surcharge would eventually be trued-up with actual spending, ratepayers will still be required to "prepay" costs related to certain investments that may never be made.

Q. What is the impact on shareholders of the Company's proposed SRRC?

A. Contrary to economic theory and good ratemaking practice, the proposed surcharge mechanism will increase shareholder return while significantly reducing risk. Shareholder return is directly proportional to the amount of investment made by the utility. Since shareholders benefit from every investment dollar that is spent by a utility, the proposed surcharge mechanism will increase overall return to shareholders and accelerate recovery of that return.

Q. Aren't ratepayers protected by the earnings test proposed by ACE?

A. No, they are not, for two reasons. First, it is undeniable that ratepayers will pay more if the surcharge mechanism is adopted. Second, the proposed earnings test includes a 50-basis point threshold, i.e., the Company can earn a return that exceeds the authorized return on equity by up to 50 basis points without incurring any ratepayer liability. Third, and perhaps most importantly, there will be very limited time to review the calculation of the earnings test and such a calculation is easily manipulated by the Company. Moreover, parties often disagree about the components of any earnings test. Therefore, I do not believe that the proposed earnings test provides ratepayers with sufficient protections against higher rates.

Pursuant to the current ratemaking mechanism, plant additions are only included in rate base, and therefore in utility rates, once the plant is completed and placed into service. Between general base rate cases, plant that is booked to utility plant-in-service is not reflected in utility rates until the Company's next base rate case. However, under the Company's proposal, ratepayers will bear higher costs sooner, as a result of the surcharge mechanism. If the SRRC is adopted, ratepayers will pay an additional surcharge each year. Moreover, these charges will include not only plant that has been completed to date, but also plant that is projected to be completed over the upcoming twelve months. From a financial perspective, these are serious detriments to ratepayers.

Q. Would the Company's proposal to implement a surcharge also shift additional risk onto ratepayers?

A. Yes, it would. The Company's proposed mechanism would shift risk from shareholders, where it properly belongs, to ratepayers without any commensurate reduction in the Company's return on equity. The SRRC will reduce shareholder risk, in two ways. First, since the surcharge mechanism will accelerate recovery, shareholders will no longer have to wait for a general base rate case to receive a return on this investment. Nor will shareholders have to wait for a general base rate case in order to begin recovery of depreciation associated with the investment. Second, given the true-up included in the surcharge mechanism, recovery of, and on, this investment is guaranteed. Under traditional ratemaking, shareholders are awarded a risk-adjusted return on equity and given the opportunity, but not a guarantee, to earn this return. Under the true-up mechanism proposed by ACE, shareholders would be guaranteed to recover both the return on this investment as well as the return of this investment. This guarantee results from the fact that any shortfalls would be charged to ratepayers in a subsequent period. This mechanism effectively eliminates all shareholder risk involving recovery of projects funded through the SRRC until the time that such projects are rolled into base rates.

Q. Is the Company proposing any reduction to its cost of equity to reflect the lower risk inherent in the SRRC mechanism?

A. No, it is not. In spite of the fact that the surcharge mechanism will reduce shareholder risk, and will transfer that risk to ratepayers, the Company has not proposed any reduction to the cost of equity to be paid by ratepayers.

Q. Don't shareholders bear the risk of having the BPU deny recovery in an subsequent prudence review?

A. While technically the investment subject to the SRRC would be reviewed for prudency in a base rate case, in my opinion there is little likelihood that the BPU will subsequently disallow the investment. The fact is that disallowance of costs recovered through a rider or surcharge mechanism is extremely rare.

Q. Will adoption of a SRRC mitigate the need for frequent rate cases?

A. While Mr. McGowan states that adoption of the mechanism "will help to lengthen the time period between the Company's requests to increase base rates…", the Company is not willing to guarantee that base rate case filings will be less frequent, or to commit to any particular schedule with regard to the filing of base rate cases.

In addition, the Company's proposed SRRC will still require the review of an annual filing, including the evaluation of an annual earnings test. Finally, the SRRC will also result in annual rate increases for New Jersey ratepayers, but those increases would be implemented without all of the ratepayer safeguards inherent in a full base rate case analysis.

Q. Is the BPU currently examining the issue of infrastructure investment?

A. Yes, it is. The BPU is currently soliciting comments on an Infrastructure Investment Program and Recovery Mechanism for New Jersey utilities. Given this review by the BPU, it is premature to consider <u>any</u> infrastructure investment recovery mechanism for ACE.

Q. Is the proposed SRRC consistent with the mechanism that is currently being considered by the BPU?

A. No, it is not. The Infrastructure Program and Recovery Mechanism that is being considered by the BPU differs from the proposed SRRC in several important ways. First, the BPU's proposal addresses <u>incremental investment</u>, while ACE's proposal would allow it to recover all reliability and emergency investment that goes into service between base rate cases. The BPU's proposal specifically requires that a baseline level of investment in each area be maintained by the utilities and recovered through the base rate case process, a provision that is absent from ACE's proposal.

Second, the BPU's proposal would be based on recovery of plant that is already in service prior to ratepayers being charged, while ACE's proposal would require ratepayers to pay for anticipated investment. Thus, the timing of recovery reflected in ACE's proposal differs significantly from the recovery mechanism proposed by the BPU.

C. Recommendation

Q. What do you recommend with regard to the proposed SRRC?

A. I recommend that the proposed surcharge mechanism be rejected. Electric utilities have a basic obligation to provide safe and reliability utility service. Investment related to meeting this obligation should be recovered through the traditional rate case process. The Company's proposal would increase costs to ratepayers and shift significant risk from shareholders to customers. Moreover, the Company's proposal is inconsistent with the Infrastructure Program and Recovery Mechanism currently being investigated by the BPU. Given the BPU's current investigation, it is premature to consider any infrastructure investment mechanism for ACE at this time. For all these reasons, I recommend that the proposed System Renewal Recovery Charge be rejected by the BPU.

Q. Does this conclude your testimony?

A. Yes, it does.