BEFORE THE STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

I/M/O THE PETITION OF ATLANTIC CITY	**)**
ELECTRIC COMPANY d/b/a CONECTIV	**) BPU DOCKET NO. ER03020110**
POWER DELIVERY FOR APPROVAL OF	**) OAL DOCKET NO. PUC 06061-03**
AMENDMENTS TO ITS TARIFF TO	**)**
PROVIDE FOR AN INCREASE IN RATES	**)**
FOR ELECTRIC SERVICE	**)**

INITIAL BRIEF OF THE NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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PROCEDURAL HISTORY

On February 3, 2003, Atlantic City Electric Company ("Atlantic" or the "Company") filed a petition with the Board of Public Utilities ("BPU" or "Board") seeking approval of a base rate increase of $68.374 million in annual revenues or a 6.9% increase. *Petition*, p. 3 The Company sought a $63.353 million increase in its distribution revenues as well as a $5.021 million net increase associated with the recovery of regulatory assets. *P-34*, p.2, *P-14*, p.7.

In support of its filing, the Company with its petition filed the testimony of J. Mack Wathen (Policy and Case Overview), Jerry A. Elliott (Capital Additions), Paul R. Moul (Capital Structure and Return on Equity), Herbert A. Chalk (Revenue Requirement), Carl D'Adamo (Cost of Service Study), Joseph F. Janocha (Rate Design) and Timothy J. White (Lead-Lag Study/Cash Working Capital). On April 16, 2003, the Company filed its Cost of Service Study with revised schedules, supplemental testimony for Mr. Janocha and an updated revised tariff.

The matter was transferred to the Office of Administrative Law ("OAL") on July 14, 2003, and subsequently assigned to an Administrative Law Judge ("ALJ"). The New Jersey Large Energy Users Coalition ("NJLEUC"), Cogentrix Energy, Inc. ("Cogentrix") and the Independent Energy Producers of New Jersey ("IEPNJ") filed motions to intervene in the proceeding.

A prehearing conference was held before the ALJ on September 30, 2003 and an Order detailing the issues and procedural schedule was rendered on October 3, 2003. On October 8, 2003, the ALJ granted the motions to intervene filed by NJLEUC and IEPNJ. And, on October 17, 2003, the ALJ denied the Cogentrix motion to intervene finding that, "Cogentrix would not be substantially, specifically and directly affected by the outcome of the proceeding." The ALJ further found that IEPNJ had been granted intervenor status and reasoned that "the interests of

Cogentrix are not sufficiently different to add measurably and constructively to the proceeding." Cogentrix was granted permission to participate, limited to the right to file a brief and to file exceptions. On Oct. 17, 2003, Cogentrix filed a motion for interlocutory review with the BPU.

Pursuant to the Prehearing Order, on October 28, 2003, the Company filed the supplemental testimony of Charles F. Morgan, Jr., Mr. Chalk and Mr. Janocha. Updated schedules were filed for Mr. White.

Atlantic filed its opposition to the Cogentrix motion on November 3, 2003 and on November 10, Cogentrix filed a response to the Atlantic opposition. On November 25, 2003, the Company filed an updated rate design proposal.

At the Board agenda meeting held on December 5, 2003, the Board directed that certain supplemental issues from three previous Atlantic dockets be incorporated into the base rate proceeding. *Order Clarifying Issues and Directing the Filing of Supplemental Testimony*, BPU Docket Nos. ER02080510, EO03020091 and EM01050308 (December 12, 2003). The transferred issues included: (1) Deferred Balance issues including the recovery of $25.4 million in MTC, NNC, and BGS deferred costs; (2) B.L. England issues including the recovery of $2.5 million in transaction costs associated with the attempted sale of B.L.England to NRG Energy, potential additional B.L. England stranded costs, and the rate treatment for ongoing B.L. England operating and maintenance expenses; and (3) issues regarding the Company's request for approval of the service agreement with Pepco Holdings, Inc. ("PHI"). The Company was directed to file supplemental testimony within 30 days addressing the additional issues that were outlined in the Order. On December 18, 2003, the Company filed revised schedules for Mr. Janocha and Mr. Morgan. The Company, at that time, also provided updates to the previously provided Rate Design work-papers.

On December 17, a public hearing was held in Mays Landing. Mr. Anthony J. Pagano, Counsel for Atlantic County, spoke at the hearing. Subsequently, Mr. Pagano filed with the Board copies of resolutions from various Atlantic County communities expressing opposition to the proposed rate increase. Resolutions were received from the City of Absecon, the City of Atlantic City, the Borough of Buena, Buena Vista Township, Hamilton Township, Mullica Township, Egg Harbor City, the Borough of Folsom, and the City of Pleasantville.

A motion requesting reconsideration, clarification and revisions to the procedural schedule established in the December 12th Board Order was filed by the Company on December 22, 2004. The Company proposed that certain issues included by the Board into the base rate case be moved to a separate Phase 2 of the base rate case.

A response to the Company's motion for reconsideration was filed by the Ratepayer Advocate on January 2, 2004 proposing that all deferred balance and B.L. England issues be put into a Phase 2 proceeding. A conference call was held with the ALJ in which the parties agreed to the consolidation of the Service Agreement docket into the current base rate case and the adoption of the Phase 2 proposal for deferred balance and B.L. England issues. The parties further agreed on filing dates for Service Agreement testimony and for the Company's testimony on the Phase 2 issues. The Board subsequently amended its December 12th Order to reflect these changes to the procedural schedule. *Order on Motion for Reconsideration*, BPU Docket Nos. ER02080510, EO03020091, EM01050308, (January 26, 2004).

On January 5, 2004, the Ratepayer Advocate filed the direct testimonies of Messrs. Peter Lanzalotta (Reliability), John Stutz (Rate Design, Service Quality), Michael Majoros (Depreciation), Matthew Kahal (Rate of Return), and Michael Dirmeier (Revenue Requirement) addressing issues raised in the base rate petition and testimony. On January 12, pursuant to the agreed upon procedural schedule, Atlantic filed the testimony of James P. Lavin addressing the issues related to the Service Agreement between Atlantic and PHI Service Company (BPU

Docket No. EM02090633).

On January 26, 2004, the Board issued an Order granting Cogentrix limited intervention in the proceeding. The Board granted Cogentrix intervenor status "limited to issues related to the Standby Electric Service ("SES") tariff rate charged to the Logan Generating Company, LP ("Logan") and Carneys Point Cogeneration Limited Partnership ("Carneys Point")." *Order on Motion for Interlocutory Review*, BPU Docket No. ER03020110, (January 26, 2004). The Board further accorded Cogentrix participant status for all other issues "limited to the right to file post-hearing briefs and to file exceptions and replies to exceptions to an Initial Decision." *Id.*

On February 10, 2004, Cogentrix filed a motion for reconsideration and clarification of the Board Order. Cogentrix asked the Board for clarification as to the scope of Cogentrix's intervention and for reconsideration based on the asserted failure of the Board to adequately consider certain facts.

Rebuttal testimonies of Messrs. Lavin, Elliott, Robinson, White, Wathen, D'Adamo, Chalk, Moul and Janocha were filed on behalf of Atlantic on February 20, 2004.

On February 23, 2004, Atlantic filed a reply to the Cogentrix motion. The Company opposed the motion for reconsideration and asserted that it continued to oppose the limited intervention granted to Cogentrix by the Board.

The Ratepayer Advocate filed the testimony of David Peterson relating to the Service Agreement on February 26, 2004.

On March 1, 2004, the Ratepayer Advocate filed a motion seeking to strike portions of the rebuttal testimonies of Mr. Chalk and Mr. Robinson. The Ratepayer Advocate argued that portions of the Company's rebuttal testimony incorporated previously denied information regarding the Company's transmission system and therefore should be stricken from the record. The Ratepayer Advocate further argued that the Company's submission of "rebuttal" testimony incorporating previously withheld information was improper and seriously compromised the Ratepayer Advocate's ability to put on its case. The Ratepayer Advocate argued in the alternative that the ALJ should amend the procedural schedule to mitigate the prejudicial impact of the Company's late filing. Also on March 1, Cogentrix filed its response to Atlantic's opposition to the motion for reconsideration and clarification.

On March 11, 2004, Board Staff responded to the Ratepayer Advocate's motion. Staff argued that rather than striking the "clearly new testimony," the ALJ should amend the procedural schedule to accommodate additional discovery and supplemental surrebuttal testimony. *Board Staff letter response to the Ratepayer Advocate motion to strike*, p.1, March 11, 2004. In response, the Company argued that the Ratepayer Advocate's motion was inappropriate because the testimony was filed "over a month before either witness is scheduled to appear on the stand in this matter." *Atlantic City Electric letter response to the Ratepayer Advocate motion to strike*, p.1, March 12, 2004. The Company further argued that the Ratepayer Advocate should have sought sanctions against the Company for its failure to respond and that the information provided should come as no surprise. *Id*. pp. 3-4. The Ratepayer Advocate filed a letter reply on March 17, 2004 asserting that it was the Company who refused to answer discovery and claimed that the information was not relevant and therefore, it was the Company, not the ratepayers who should bear the responsibility for this action, that the Ratepayer Advocate was not obligated to seek sanctions to force the Company to provide information it claimed was irrelevant. *Ratepayer Advocate letter reply brief*, March 17, 2004.

The Ratepayer Advocate filed surrebuttal testimonies of Messrs. Lanzalotta, Dirmeier, Stutz, Kahal and Majoros on March 19, 2004.

A conference call was held with the ALJ on March 22. The Ratepayer Advocate's motion to strike was withdrawn after the Company agreed to allow the Ratepayer Advocate additional time to review the new material provided in the Company's rebuttal testimony and to file supplemental surrebuttal testimony.

A motion to strike portions of Ratepayer Advocate witness John Stutz's surrebuttal testimony was filed on behalf of NJLEUC on March 22, 2004. A motion seeking to compel Board Staff to respond to discovery was filed on the same date by NJLEUC. Staff filed a response to the motion to compel on March 22, 2004. The ALJ advised the parties by letter that both motions would be argued at the an upcoming hearing. Evidentiary hearings were scheduled for March 23, 24, 25, 30, 31, April 2, 5, 6 and 7, 2004.

At the evidentiary hearing on March 24, the ALJ heard arguments on the pending motions from NJLEUC, Atlantic, Board Staff and the Ratepayer Advocate. From the bench the ALJ denied the NJLEUC motion to strike the testimony of Dr. Stutz finding that the surrebuttal was "simply that, it's surrebuttal to prior testimony." T155:L3-4. The ALJ then told the parties that the response to the Staff's discovery request, that was the basis for the motion to compel, would not be allowed into the record "without an expert witness supporting both the concepts and the details." T154:L5-10 Accordingly, the Judge reserved on the motion to compel, advising the parties that if the alternative cost of service study was allowed into the record, he would review that decision. T154:L16-21. Subsequently, the ALJ sustained the objection of the Company and denied Staff's request to enter Staff exhibit S-2, the alternative cost of service study, into evidence. T243:L5-10.

On March 31, 2004, Board Staff requested interlocutory review of the March 24, 2004 ruling by the ALJ.

On April 5, 2004 the Ratepayer Advocate filed supplemental surrebuttal testimony responding to the rebuttal testimony of Company witness Robinson.

At a Board agenda meeting held on April 14, 2004, the Board directed that the Staff's exhibit S-2 be put into evidence. The Board found that it was "reasonable and appropriate for Board Staff to seek to include in the record herein the results of a cost allocation based upon demand and energy." The Board further found that there was no requirement that Staff produce a sponsoring witness to be available for cross examination. *Order on Motion for Interlocutory Review*, April 30, 2004. May 26, 2004 was agreed upon as an additional hearing date to allow cross examination of the Company's witness on the Staff exhibit S-2.

At the conclusion of the evidentiary hearings, briefing dates were established. The parties were advised by the ALJ to meet to discuss possible settlement of the case. If an agreement could not be reached, initial briefs were due June 4, 2004 and reply briefs were due June 18, 2004. The brief filing date was later extended to June 18, 2004. The filing date for the initial brief was later extended to August 4 and the date for the reply brief was extended to August 18.

POINT I

COST OF CAPITAL

YOUR HONOR AND THE BOARD SHOULD ADOPT AN OVERALL RATE OF RETURN OF 7.66%, REFLECTING ADJUSTMENTS TO THE COMPANY'S *PRO FORMA* CAPITAL STRUCTURE FOR THE INCLUSION OF SHORT-TERM DEBT, THE UNAMORTIZED BALANCE OF CALL PREMIUMS, NEW DEBT ISSUANCES AND REFINANCINGS, AND A 9.25% RETURN ON EQUITY.

Ratepayer Advocate witness Matthew Kahal originally recommended a cost of equity of 9.25%, and an overall cost of capital of 7.74%. *RA-18*, Attach. Adjusted to reflect the completion of Atlantic's planned refinancings, consistent with Mr. Kahal's recommendations, the overall recommended return is 7.66%. *Schedule DRA-1* (attached hereto as Exhibit A). As set forth below and in Mr. Kahal's testimony, his recommendation is the product of the sound application of recognized methodologies, resulting in a reasonable cost of equity and overall return. *See RA-17*, *-18*.

In contrast, Company witness Mr. Paul R. Moul recommends a cost of equity of 11.5%, and an overall rate of return of 9.03%. *P-21*, p.1. Notably, Mr. Moul's recommended cost of equity is considerably in excess of that recommended by Mr. Kahal, and in excess of cost of equity determinations made by the Board in recent (2003) electric utility base rate cases.[1] However, as set forth in detail below and in the filed testimony of Mr. Kahal, the analyses underlying Mr. Moul's cost of equity recommendation are riddled with flaws and unreasonable assumptions which undermine their usefulness in a rate setting proceeding. Mr. Kahal found

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[1] *See I/M/O PSE&G*, BPU Dkt. Nos. ER02050303, et al (Decision and Order, 4/22/04); *I/M/O JCP&L*, BPU Dkt. Nos. ER02080506, et al (Final Order, 5/17/04); and *I/M/O Rockland Electric Company*, BPU Dkt. Nos. ER02080614, et al (Final Decision and Order, 4/20/04).

that his analysis shows that Mr. Moul's calculations support a cost of equity in the 9-10% range, not 11.5%. *RA-18*, p. 5.

Furthermore, as set forth below and in Mr. Kahal's testimony, Mr. Moul unreasonably excluded short-term debt and unamortized call premiums from the Company's capital structure. In contrast, Mr. Kahal included both in his recommended capital structure so that ratepayers may benefit from the lower cost of capital resulting from their inclusion, much like Atlantic's shareholders.

For the reasons set forth below and in the filed testimony of its witness, the Ratepayer Advocate respectfully submits that Mr. Kahal's cost of equity and overall return calculations are reasonable and should be adopted by Your Honor and the Board.

A. Capital Structure

1. Overview

Both Mr. Kahal and Mr. Moul start with the June 30, 2003 *pro forma* capital structure as the basis for their respective capital structure recommendations.[2] Both Mr. Kahal and Mr. Moul also agree that the capitalization of Atlantic City Electric Transition Funding, LLC, amounting to $2.2 million, should not be included in the equity balance for capital structure purposes. *RA-18*, p. 4. However, their respective capital structure recommendations differ based on their treatment of two items: debt reacquisition costs and short-term debt.

As set forth below and in the testimony of Mr. Kahal, the inclusion of short-term debt and debt reacquisition costs in Atlantic's capital structure is reasonable and should be adopted by Your Honor and the Board.

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[2] In his rebuttal testimony, Mr. Moul updated his recommendations using the June 30, 2003 balance. *P-22*. In his initial testimony, Mr. Moul used the Company's capital structure as of December 31, 2002 as the basis for his adjustments. *P-20*, p. 17.

2. Inclusion of Debt Reacquisition Costs

Atlantic incurs near-term debt reacquisition costs in the form of call premiums. *RA-17*, p. 13. At issue is the treatment of the unamortized call premium amount <u>for capital structure purposes</u>, namely, whether the unamortized call premium should be included in the debt balance. The unamortized call premium at issue amounts to $10.2 million. *P-21*, Schedule 6, p. 1; *RA-18*, pp. 21-22. Exclusion of the unamortized call premium from the debt total has the effect of increasing the equity ratio and decreasing the debt ratio. Conversely, including the unamortized call premium in the debt total has the effect of decreasing the equity ratio and increasing the debt ratio.

Ratepayer Advocate witness Kahal includes the unamortized balance of call premiums in the debt total for capital structure purposes. Mr. Kahal's inclusion of the unamortized call premium is consistent with financial accounting practice and the treatment accorded by credit rating agencies and securities analysts. *RA-17*, pp. 14-15.

In contrast, Mr. Moul adjusts the debt balance for capital structure purposes to exclude the unamortized balance of call premiums, thereby inflating the equity balance. Insofar as Mr. Moul's treatment of the unamortized call premium is inconsistent with financial accounting practice and the treatment accorded by rating agencies and credit analysts, his failure to adjust the debt balance artificially inflates Atlantic's equity ratio. Therefore, Mr. Moul's exclusion of the unamortized call premium for the debt balance should be rejected.

Furthermore, as Mr. Kahal testified, his recommended treatment of call premiums fairly provides Atlantic with a "return of and a return on" its call premium costs. *RA-17*, p. 13. As discussed in more detail below, for the purpose of calculating the Company's <u>cost of debt</u>, Mr. Kahal accepts Mr. Moul's proposed methodology, whereby the cost of debt calculation includes the call premium amortization expense, and the unamortized call premium balance is deducted from the debt balance for that calculation. *Id*.

3. Inclusion of Short-Term Debt

Mr. Kahal's recommended capital structure recognizes that the Company uses short-term debt to fund its operations. *RA-17,* p. 15. As Mr. Kahal testified, short-term debt is Atlantic's least expensive source of investor-supplied capital, and excluding short-term debt would overstate the Company's cost of capital to the detriment of its ratepayers. *Id*. Furthermore, Mr. Kahal's inclusion of short-term debt recognizes that credit rating agencies and securities analysts also consider short-term debt in their analyses. *Id*.; *RA-18*, p. 20. As Mr. Kahal testified, "to the extent short-term debt affects debt and equity costs, ratepayers pay those costs." *RA-17,* p. 15. Therefore, it would be unreasonable for ratepayers not to benefit from the use of lower cost short-term debt in the capital structure of the Company.

Mr. Kahal's recommended capital structure reflects the inclusion of $40.8 million of short-term debt. *RA-17*, p.14. Mr. Kahal based his recommended amount of short-term debt on a 12-month average of Atlantic's actual short-term debt experience. *Id.*, p. 15. In contrast, Mr. Moul excluded short-term debt from his recommended capital structure.

Mr. Moul's reasons for excluding short-term are debt are unpersuasive. In his rebuttal testimony, Mr. Moul proffered several reasons to exclude short-term debt. *P-21*, p. 8. First, Mr. Moul testified that short-term debt was used by the Company to "pre-fund" temporary redemptions of long-term debt. *P-21,* pp. 8-9; *See RA-18,* p. 19. However, even if Mr. Moul's assertion was to be accepted, Mr. Kahal found the Company's short-term borrowings to be much larger than the Company's pre-funding balances. *RA-18*, p. 19. Furthermore, Mr. Kahal found that Mr. Moul's rationale for their exclusion is premised on the implicit faulty assumption that short-term debt is the only type of capital used for pre-funding, ignoring internally generated cash and other sources. *RA-18*, pp. 19-20. Similarly, Mr. Kahal found Mr. Moul's testimony that Atlantic's loans to the PHI Money Pool constitute "negative short-term debt" to be novel and unpersuasive. *P-21*, pp. 9-10; *RA-18*, p. 19. Notably, Mr. Kahal testified while utilities may sometimes maintain cash balances or have short-term investments, "there is no such thing as 'negative short term debt.'" *RA-18*, p. 19, ln. 19.

Mr. Moul also claims that the level of short-term debt used by Mr. Kahal is unrepresentative of the amount needed to meet the Company's liquidity needs. *P-21*, p. 8. However, while Mr. Moul's claim was unsupported, Mr. Kahal's short-term debt amount was based on a 12-month average of <u>actual</u> Company experience.

Finally, in response to a discovery request, Atlantic claims short-term debt was excluded because the Company allocates short-term debt to construction work in progress ("CWIP"). *RA-17*, p. 16. Yet Mr. Kahal found that Atlantic's allowance for funds used during construction ("AFUDC") accruing CWIP amounted to only $13 million at year-end 2002. *Id*. Thus, Mr. Kahal concluded that ratepayers would receive only a small portion of the cost of capital savings attributable to the lower short-term debt cost rate through the AFUDC. *RA-18*, p. 21.

In sum, by including short-term debt in the Company's capital structure, Mr. Kahal recognizes that the Company uses short-term debt to fund its operations and that rating agencies consider short-term debt in their analyses. Including short-term debt in the Company's capital structure for ratemaking purposes would provide ratepayers with the benefits of lower-cost short-term debt.

4. Capital Structure Summary

Atlantic's shareholders benefit from the use of short-term debt and debt reacquisition costs. Atlantic's ratepayers should similarly benefit from a capital structure which includes such costs. For the reasons set forth above and in the testimony of Mr. Kahal, the short-term debt and unamortized debt reacquisition costs should be included in the Company's capital structure for ratemaking purposes.

B. Cost of Debt and Preferred

1. Cost of Short-Term Debt

As discussed in more detail above, Ratepayer Advocate witness Kahal recommends that short-term debt be included in Atlantic's capital structure. Mr. Kahal uses a reasonable cost rate for short term debt, based on the Company's actual debt cost. Mr. Kahal assigns a cost rate of 2.00% to short-term debt. *RA-17,* Schedule MIK-1, footnote 1; *RA-18*, Attachment. Mr. Kahal's recommended cost rate for short-term debt is based on the 12-month average for the period ending June 30, 2003, where the 2.00% rate approximates the actual cost rate during that time.

2. Cost of Preferred

There is no dispute between the Company and the Ratepayer Advocate with respect to the proper rates for Preferred Stock and Trust Preferred Capital Securities. Ratepayer Advocate witness Kahal and Company witness Moul agree that the proper cost rates for Preferred Stock and Trust Preferred Capital Securities are 4.27% and 7.84%, respectively. *P-21*, Exh. PRM-4, p. 1; *RA-18*, Attachment. The agreed-upon rates are the June 30, 2003 cost rates provided by the Company in response to discovery request RAR-ROR-35. *RA-17*, p. 13.

3. Cost of Long-Term Debt

Mr. Kahal recommended a long-term debt cost rate of 6.92%, subject to the provision that the cost of debt should be updated for planned long-term debt financings. *RA-17*, p. 13; *RA-*

18, p. 22. At that time, Atlantic sought to undertake additional refinancings through the issuance of new long-term debt, pursuant to recent Board authorization. *See I/M/O Atlantic City Electric Company*, BPU Dkt. No. EF03070545 (Order of Approval, 12/18/03). In contrast, Company witness Moul objects to recognizing cost savings attributable to the planned debt refinancing. Since the time when the testimony was filed, Atlantic issued new long-term debt and redeemed certain higher cost debt, as set forth in RPA-TR-3 Supplemental (*RA-63*) and discussed in more detail below.

The recommended long-term debt cost rate Mr. Kahal presented, 6.92%, represented the upper end of estimates of Atlantic's cost of debt provided in response to discovery in Atlantic's refinancing docket (BPU Dkt. No. EF03070545), and reflected the then-anticipated issuance of new long-term debt at an assumed rate of 6.52%. *RA-17*, p. 13; *RA-18*, p. 23. In contrast, Company witness Moul recommends a long-term debt cost rate of 6.97%, which does not reflect the effect of the then-planned refinancings. In his rebuttal testimony, Mr. Moul disagrees with Mr. Kahal's proposal to reflect the refinancings, reasoning that the Company does not know what interest rates will be when the SEC approval is obtained. *P-21*, p. 14. However, at hearing, Mr. Moul testified that "[w]e should reflect any cost savings from a refinancing once we know what that cost would be." T566:L1-T566:L2.

Now, the results of the long-term issuance and bond refinancings are known and the capital structure and cost of capital calculations should reflect the results. The results of the Company's recent $120 million bond issuance and redemptions were presented in the Company's response to RPA-TR-3 Supplemental (*RA-63*). The Company used the proceeds of the bond sale, along with $17.5 million in cash, to redeem $62.5 million in principal amount of Atlantic 7% First Mortgage Bonds due September 1, 2023, and $75 million in principal amount of Atlantic 7% First Mortgage Bonds due August 1, 2028. *RA-63* (RPA-TR-3). The issuances of new debt and the refinancings lower the cost of debt to 6.71%, and slightly change the capital structure since some internally generated cash was used for the refinancings. The benefits of the refinancings should not inure only to the Company's shareholders. Atlantic's ratepayers should benefit from the refinancings as well. The Ratepayer Advocate's recommended updated rates and capital structure are presented herein in Schedule DRA-1 (Exhibit A).

In computing the long-term debt cost rate, both Mr. Moul and Mr. Kahal included the call premium amortization expense. *RA-17*, p. 13. However, as discussed in detail above, Mr. Kahal and Mr. Moul disagree on the treatment of the call premium <u>for capital structure purposes</u>. Their calculation of the cost rate for long-term debt includes the call premium amortization expense, amounting to $1.08 million. *Id*. Furthermore, as Mr. Kahal testified, the inclusion of this amount in the debt cost rate calculation allows Atlantic to recover the principal amount of the call premium over time. *Id*. When this cost rate computation methodology is coupled with Mr. Kahal's recommended inclusion of the unamortized call premium in the long-term debt balance for capital structure purposes, Mr. Kahal testified that the Company is provided with a "return of and on" the call premium, "i.e., full cost recovery," contrary to Mr. Moul's claims. *RA-17*, p. 13.

C. Cost of Equity

Mr. Kahal recommends a return on equity for Atlantic of 9.25%. As set forth below and in his filed testimony, Mr. Kahal's recommendation is based upon a well-reasoned application of the standard discounted cash flow ("DCF") model applied to a select proxy group of electric utility companies of similar risk as Atlantic. *RA-17*, pp. 17-30. Furthermore, as a check on his DCF results, Mr. Kahal also prepared an analysis using the capital asset pricing model ("CAPM"). Mr. Kahal's cost of equity recommendation, based on the sound application of recognized models, is reasonable and fairly compensates Atlantic's investors.

In contrast, in his rebuttal testimony Mr. Moul recommended a cost of equity of 11.50%.[3] *P-21*, pp. 12-30. However, as set forth below and in Mr. Kahal's filed testimony, Mr. Moul's cost of equity recommendation is based upon flawed application of models and overstated variables, resulting in an unreasonably high cost of equity recommendation. Furthermore, Mr. Moul's recommended cost of equity is far greater than that recently approved by the Board for other electric utilities.[4]

1. Mr. Kahal's Application of the Discounted Cash Flow ("DCF") Model

The basic principle underlying the DCF method is that a stock price will reflect the discounted stream of cash flows expected by investors. *RA-17*, p. 19. Mr. Kahal utilized the constant growth DCF model as the basis for his return on equity recommendation. As Mr. Kahal testified, the DCF method has been widely used in New Jersey and is the most widely used cost of equity methodology. *Id*. The constant growth DCF model assumes, for mathematical simplicity, that an investor's required return on equity is equal to the dividend yield, plus expected rate of growth, and assumes further that the growth rate is constant for an indefinitely long period. This relationship is expressed mathematically as:

$$K = D/P\ (1 + 0.5g) + g$$

where, "K" is the cost of equity capital, "D/P" is the dividend yield (the current annualized dividend divided by the stock price), and "g" is the expected growth rate. *RA-17*, p. 19. While

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3 In his initial testimony, Mr.Moul recommended a cost of equity of 12.50%. *P-20*, p. 1.

4 In recent (2003) electric utility base rate cases, the Board awarded equity returns in the range of 9.5-9.75%. *See I/M/O PSE&G*, BPU Dkt. Nos. ER02050303, et al (Decision and Order, 4/22/04); *I/M/O JCP&L*, BPU Dkt. Nos. ER02080506, et al (Final Order, 5/17/04); and *I/M/O Rockland Electric Company*, BPU Dkt. Nos. ER02080614, et al (Final Decision and Order, 4/20/04).

Mr. Kahal recognized that the constant growth model may be unrealistic in some cases, for regulated public utilities it may be reasonable, since they are more stable than unregulated companies. *RA-17*, p. 19. While the DCF model may be applied to a single publically-traded company, since Atlantic is a subsidiary of a publically traded company, PHI, Mr. Kahal recognized that a proxy was needed. *RA-17*, p. 20. Thus, Mr. Kahal proceeded to select a proxy group of companies with a risk profile similar to Atlantic's. *Id*.

Mr. Kahal selected his proxy group from the Value Line "Electric Utilities East" industry group. *Id*. Those in his proxy group of eight electric utilities shared many common characteristics. Much like Atlantic, they have substantially or fully divested their generating assets, they operate in retail access states and, with the exception of one, operate as part of a transmission RTO or ISO. *Id*. In selecting his proxy group, Mr. Kahal also considered other risk indicators, including Value Line safety ratings, bond ratings, beta statistics, and common equity ratios. *Id.*, also Schedule MIK-4.

Mr. Kahal utilized his proxy group to measure the dividend yield component (D/P) of the DCF formula. Mr. Kahal examined the dividend yield of his proxy group over a six-month period, from June through November 2003. *Id*., p. 22. Mr. Kahal found that over that period, his proxy group's average dividend yield averaged 5.35%, with the group average showing a decline over the period examined, ranging from 5.56% in July to 5.09% in November. *Id*. Mr. Kahal selected the 5.35% average as the dividend yield starting point for his application of the DCF model. To the 5.35% group average dividend yield, Mr. Kahal applied the "half year" adjustment technique, using a figure of 2%, to yield an adjusted dividend yield of 5.5% (i.e., 5.35% x 1.02). *Id*.

The next step in applying the DCF method is to estimate "g", the growth rate. One avenue tried by Mr. Kahal to estimate the growth rate was a look back on historical data. Mr.

Kahal examined historical earnings per share ("EPS"), dividend, and book value growth data for his proxy group over a five-year time span, but found the historic measures to be highly volatile, providing little useful information. *Id*., p. 23, Schedule MIK-5. Mr. Kahal was not surprised by the unhelpful historical data, citing the corporate and regulatory restructuring process over the five-year period. *Id*. Furthermore, the growth rate should be prospective, for which the historical growth rates provided limited help.

Mr. Kahal used four well-known sources of growth rate projections generated by securities analysts to derive the prospective growth rate, "g", for use in his DCF model: First Call, Zacks, Standard and Poors, ("S & P") and Value Line. *RA-17*, p. 23. The first three sources provide averages of surveys of securities analysts, while the fourth is a single source. *Id*. Mr. Kahal found that for his eight proxy companies, the four sources yielded growth rates which ranged from 3.4% (First Call) to 4.0% (S&P). *Id.* In turn, Mr. Kahal adopted a growth rate range of 3.5% to 4.0% for DCF purposes. *Id*. As a check on his range for growth rates, Mr. Kahal compared his range to growth projections for dividends, book values and retained earnings growth published by Value Line. *Id*., p. 24, Schedule MIK-5. The Value Line estimates for his eight proxy companies range between 3.1% to 4.5%. *Id*. This check showed that Mr. Kahal's recommended range of growth rates is reasonable, falling within the range shown by the Value Line sample.

Adding these growth rate projections to the dividend yield of 5.5%, yields a range of returns on equity from 9.00% to 9.50%. *Id*. Mr. Kahal's recommended return on equity of 9.25% is the midpoint of the range.

2. Mr. Kahal's Application of the Capital Asset Pricing Method ("CAPM")

Mr. Kahal also employed the CAPM to derive a return on equity reference point as a check on his DCF results. As Mr. Kahal testified, the CAPM is the next most common model for deriving cost of equity in rate cases, after the DCF method. *RA-17*, p. 26.

The CAPM method is a "risk premium" approach, where the cost of equity is equal to the yield on a risk-free asset, plus a market risk premium multiplied by the firm's Beta, a measure of the firm's risk relative to the market. *RA-17*, p. 26. Mathematically, the CAPM can be expressed as follows:

$$K = Rf + B(Rm - Rf)$$

where, "K" is the firm's cost of equity; "Rm" is the expected return on the overall market; "Rf" is the yield on a risk-free asset; and "B" is the firm's beta. *Id*. The risk premium is the amount by which the expected return exceeds the yield on a risk-free asset.

Two of the three variables in the CAPM equation are readily observable: the return on a risk-free asset ("Rf") and the beta measure ("B"). *RA-17*, p. 27. For his calculation of the cost of equity using the CAPM, Mr. Kahal used the long-term Treasury yield as the return on a risk-free asset ("Rf"). *Id*., p. 27. Mr. Kahal found that the yield on long-term Treasuries range from 5.0% to 5.5%. *Id*. In his filed testimony, Mr. Kahal cautioned that long-term Treasuries are not risk free, because of "interest rate risk." *RA-17*, p. 30. Thus, the risk-free rate used by Kahal is artificially high, which would render his resultant CAPM-based cost of equity calculations conservatively high. *Id*.

For beta ("B"), Mr. Kahal used the average beta of his eight-company proxy group, 0.64%. *Id*. However, as set forth below and in Mr. Kahal's filed testimony, Mr. Kahal recognized that the measurement of the market return (Rm) is more difficult. *Id*.

For the market return variable (Rm) Mr. Kahal first considered various measures of market return, including measures by Value Line (per Moul), Ibbotson, Ibbotson/Chen, and the Value Line Industrial Composite. *RA-17,* Schedule MIK-7, page 2. Mr. Kahal found that the market return estimates ranged from 10.75% to 11.65%, and averaged around 11.25%. *Id.* For purposes of his application of the CAPM method, Mr. Kahal used a range of market return measures – 11.0%, 11.5%, and 12.0% -- yielding costs of equity of 8.84%, 9.25%, and 9.66%, respectively. *Id.*, p. 27 and Schedule MIK-7, p. 1.

However, as noted above and in Mr. Kahal's filed testimony, the use of the Treasury rate as the risk-free rate in his application of the CAPM results in "high side" estimates and he testified that greater weight should be given to the lower end of his range of CAPM results. *RA-17,* p. 30. Recognizing that his CAPM-based estimates were conservatively high, Mr. Kahal used the midpoint of the cost of equity range (from 8.8% to 9.7%), 9.25%, as the basis for comparison to his DCF-based recommendation. A comparison to his CAPM-based results confirms the reasonableness of his recommended cost of equity, 9.25%, which was calculated using the DCF method. *Id*.

3. Mr. Moul's Derivation of his Recommended Return on Equity

Mr. Moul recommended a cost of equity of 11.5%. *P-21*, p. 1. Mr. Moul's cost of equity recommendation is far higher than that recommended by Mr. Kahal and the cost of equity determinations made by the Board in recent (2003) electric base rate cases. Surprisingly, Mr. Moul's initial recommended cost of equity of 12.5%, as set forth in his filed initial testimony, was even higher. In his filed rebuttal testimony, Mr. Moul revised his cost of equity recommendation. *Id*. Mr. Moul based his recommendation on the application of four methodologies: the DCF method, the Risk Premium method, the CAPM method, and Comparable Earnings. However, as set forth below and in the filed testimony of Mr. Kahal, Mr.

Moul's analysis is flawed, marked by the use of variables which overstate results, resulting in an overstated cost of equity calculation.

a. Mr. Moul's Application of the DCF Method

One of the methods Mr. Moul used to derive his cost of equity estimate was the DCF method. Notably, Mr. Moul's DCF-derived estimate (10.38%) *P-21*, p. 15 is significantly higher than that recommended by Mr. Kahal (9.25%). Much of the difference between Mr. Kahal's DCF-derived cost of equity recommendation and Mr. Moul's estimate is attributable to adjustments included in Mr. Moul's DCF formula which Mr. Kahal found were inappropriate: a "leverage" adjustment and a "float" adjustment. *RA-18*, p. 6. If Mr. Moul's leverage adjustment and float adjustment were excluded, the resulting cost of equity would be 9.59%. *Id*. Furthermore, as set forth below and in Mr. Kahal's filed testimony, Mr. Moul's proxy group of companies differs significantly from Atlantic, and their use overstates Mr. Moul's cost of equity calculation.

Mathematically, Mr. Moul's application of the DCF method may be expressed as follows:

$$D/P + g + lev = k \text{ x } flot = K$$

where "D/P" is the six-month adjusted forward-looking dividend yield; "g" is the growth rate; "lev." is Mr. Moul's "leverage adjustment;" "flot."is Mr. Moul's adjustment for "flotation costs;"and "K" is cost of equity. *P-21*, p. 15. With Mr. Moul's estimate for each variable plugged in, his DCF formula reads as follows:

$$D/P + g + lev = k \text{ x } flot = K$$

$$4.34\% + 5.25\% + 0.59\% = 10.18\% \text{ x } 0.20 = 10.38\%$$

P-21, p. 15. The impact of the two flawed adjustments proposed by Mr. Moul – the leverage adjustment and the float adjustment - are readily apparent in the formula above.

As noted above and in Mr. Kahal's filed testimony, the first adjustment -- the leverage adjustment – is responsible for much of the disparity between Mr. Kahal's and Mr. Moul's cost of equity result using the DCF method. If Mr. Moul's leverage adjustment was removed, his calculation would move closer to Mr. Kahal's. Moreover, Mr. Moul's proffered leverage adjustment is based on a faulty premise, as Mr. Kahal testified. *RA-18*, p. 7. The leverage adjustment was proffered by Mr. Moul as way to "recognize that the book value equity ratio is used in the rate setting process rather than the market value equity ratio related to stock price. " *P-21*, p. 15. However, as noted by Mr. Kahal in his filed rebuttal testimony. "[t]he use of book equity in capital structure is not some defect that requires correction in the form of an extraneous 'leverage adjustment,' but rather book values are entirely consistent with cost-based ratemaking." *RA-18*, p. 7. In fact, at hearing, Mr. Moul testified that, to the best of his knowledge, his leverage adjustment was never adopted in an electric utility case. T599:L9-12.

Mr. Moul describes his second adjustment, the float adjustment, as a measure to reflect flotation costs associated with the issuance of equity shares. *P-21*, p. 15. Flotation costs are those incurred with public offerings of common stock, such as investment banking fees. However, as Mr. Kahal testified, the flotation adjustment is not needed since no such expenses were identified and, furthermore, although PHI might have recently issued new equity, it does not appear that Atlantic benefitted from an equity infusion. *RA-17*, pp. 18-19. Nor does PHI have any plans to infuse Atlantic with additional equity. *Id*. Mr. Moul's flotation adjustment is thus based on an unreasonable assumption and operates to inflate his return on equity calculation and, therefore, should be rejected.

Finally, Mr. Moul's proxy group of companies does not reflect the risk profile of Atlantic. *RA-17*, pp. 24-26. Unlike Atlantic, five of Mr. Moul's six proxy companies have significant unregulated generation and nuclear operations, which are riskier business areas than Atlantic's distribution operations. *Id*., pp. 20, 26. Thus, the proxy group selected by Mr. Moul provides an unreasonable measure of the dividend yield and growth rate projections in Mr. Moul's DCF model and would, consequently, overstate Atlantic's cost of equity. *Id*., p. 18.

In sum, Mr. Moul's inclusion of flotation and leverage adjustments, and his use of a proxy group with a risk profile unlike Atlantic's, operate to overstate his DCF cost of equity calculation.

b. Mr. Moul's Application of the Risk Premium Method

In his prefiled testimony, Mr. Kahal testified to the limited applicability of Mr. Moul's updated Risk Premium method. The Risk Premium is based on a calculation of after-the-fact returns on utility stocks versus public utility bonds over a chosen period. *RA-18*, p. 12. Mr. Kahal found that Mr. Moul's updated Risk Premium method "has little relevance to Atlantic's distribution operations, and it is not a method commonly used by investors." *RA-18*, p. 14. He concluded, "[a]t best, it is only a check" and did not find Mr. Moul's Risk Premium calculation "reliable." *Id*., p.14, ln. 12; p. 12.

Fundamentally, Mr. Kahal found that Mr. Moul's Risk Premium calculation suffers from two major flaws. First, Mr. Moul's S&P sample of utility returns was characterized by Mr. Kahal as a "diverse group of companies which includes gas utilities, gas pipeline companies, and several companies with 'junk' bond ratings or near bankruptcy." *RA-18*, p. 13, ln. 21-22. Of the approximately 35 companies in the S&P group, Mr. Kahal found that only one could be considered an electric distribution company like Atlantic. *Id*. Second, Mr. Kahal questioned the value of Mr. Moul's Risk Premium analysis, since it is not an accepted cost of equity analysis. *Id*., p. 14. Mr. Kahal testified that "[s]ome investor analysts do examine historic returns as one method of estimating a risk premium, but they normally do so for the overall stock market, not for an individual company." *Id*., ln. 3-5. In short, Mr. Moul's Risk Premium calculation is of questionable worth.

Mr. Kahal also identified other flaws in Mr. Moul's updated Risk Premium analysis which cast a further shadow over it. *RA-18*, pp. 12-14. First, Mr. Moul includes the median value in measuring average historic risk premium, thereby overstating the risk premium. Instead of using an average of only the geometric mean risk premium and arithmetic mean risk premium (3.9%), Mr. Moul averages-in the median risk premium and arrives at a figure of 4.5%. *Id*., p. 13. As Mr. Kahal noted, unlike Mr. Moul, financial analysts do not accept averaging-in the median historic return in measuring historic returns. *Id*. Second, Mr. Kahal found that Mr. Moul used a bond yield figure which did not reflect more recent data. Mr. Moul used a 6.5% bond yield, whereas Mr. Kahal found that bond returns in March 2004 were in the 6.0-6.2% range. *Id*. Finally, Mr. Kahal found that Mr. Moul also included the aforementioned flawed leverage adjustment in his Risk Premium calculation.

Mr. Kahal tested the impact of changing several variables in Mr. Moul's Risk Premium calculation. He found that using a 3.9% risk premium and bond yields in the 6.0-6.2% range, implies a current cost of capital of around 9.9-10.1%, instead of the 11.2 % arrived at by Mr. Moul. *Id*. However, given the numerous flaws identified by Mr. Kahal, Mr. Moul's Risk Premium calculation is, as noted by Mr. Kahal, at best only a check and does not contradict Mr. Kahal's lower cost of equity calculation. *Id*.

c. Mr. Moul's Application of the CAPM Method

As Mr. Kahal set forth in his prefiled testimony, Mr. Moul's application of the CAPM is fraught with unreasonable assumptions. *RA-18*, pp. 14-17. First, Mr. Moul uses a Beta of 1.01, which assumes that Atlantic's regulated distribution utility operations are riskier than the average unregulated company.[5] *Id*., p. 15. Mr. Moul's Beta is based on a leverage adjustment. His proxy group Beta average of 0.8 is adjusted upward to 1.01 for leverage. *Id.*, p. 14. As set forth above, a leverage adjustment is unnecessary and operates to inflate Mr. Moul's cost of equity calculation. Absent the leverage adjustment, the CAPM calculation using Mr. Moul's variables would yield a cost of equity of 10.32%. *Id.*, p. 15.

In addition, as pointed out by Mr. Kahal in his filed testimony, Mr. Moul's CAPM analysis incorporates unreasonable estimates of the risk-free return, an unrepresentative proxy group of companies, and a likely overstated risk premium. *Id*., p. 15. Mr. Kahal concluded that correcting Mr. Moul's CAPM analysis to resolve some portion of these issues would lower the CAPM results from 10.32% to under 10.00%. *Id*.

d. Mr. Moul's Application of the Comparable Earnings Method

As Mr. Kahal testified, Mr. Moul's comparable earnings analysis should be accorded no weight in determining Atlantic's allowed cost of equity. *RA-18*, p. 17. Mr. Moul's "updated" comparable earnings' figures exceed 14%. *P-21*, p. 19 and Exh. PRM-4, p. 35, Sch. 15. Mr. Kahal observed that Mr. Moul's updated comparable earnings figures have barely budged from those found in his initial testimony, while Mr. Moul's corresponding cost of equity estimates declined by 2 percentage points. *RA-18*, p. 17. Mr. Kahal testified that Mr. Moul's comparable earnings estimates are "not even in the same ballpark," considering that his corrections of Mr. Moul's cost of equity estimates are in the 9-10% range. *RA-18*, p. 17, ln. 17. Mr. Kahal reasonably concluded that the returns found in Mr. Moul's comparable earnings analysis "are simply not returns available today to investors on a long-term sustained basis." *Id*., ln. 20-21.

[5] The Beta for the S&P 500 is 1.00.

Mr. Moul's proffered comparable earnings analysis should therefore be rejected by Your Honor and the Board.

4. Cost of Equity Summary

As set forth above and in Mr. Kahal's filed testimony, Mr. Kahal's recommended cost of equity rate of 9.25% is reasonable and should be adopted. Contrary to Mr. Moul's claims, the rate of 9.25% is not inadequate. Mr. Moul's criticism, in part, is based on his belief that returns should match Value Line's projections. In his filed surrebuttal testimony, Mr. Kahal effectively rebuts Mr. Moul's claims. *RA-18,* pp. 25-30. Mr. Kahal notes that the Board's objectives should not be to match Value Line's projections of utility returns. *Id*., p. 27. In sum, the Ratepayer Advocate's recommended cost of equity, based on sound analysis, is reasonable and should be adopted.

D. Cost of Capital Conclusion

For all the reasons set forth above and in the filed testimony of its witness, the Ratepayer Advocate respectfully submits that Your Honor and the Board should adopt a cost of equity of 9.25% and an overall return of 7.66% for Atlantic. This recommendation reflects reasonable adjustments to the Company's capital structure for unamortized call premiums and short-term debt, as well as the lower debt costs resulting from completed refinancings. Furthermore, the Ratepayer Advocate's cost of equity recommendation is based upon the sound application of recognized methodologies.

POINT II.

REVENUE REQUIREMENT

THE APPROPRIATE *PRO FORMA* RATE BASE AMOUNTS TO $ 614,769,000 WHICH IS $ 33,305,000 LOWER THAN THE *PRO FORMA* RATE BASE PROPOSED BY ATLANTIC CITY ELECTRIC OF $648,074,000.

A. Overview

This section of the brief presents the Ratepayer Advocate's recommended overall position regarding the Company's revenue requirement. In determining the recommended revenue requirement for Atlantic City Electric, the Ratepayer Advocate relies upon the recommendations made by its revenue requirement expert, Mr. Michael Dirmeier, in addition to recommendations made by other Ratepayer Advocate expert witnesses. Specifically, the Ratepayer Advocate relies upon the return on equity number recommended by Mr. Matthew Kahal, the Ratepayer Advocate's return on equity and capital structure expert, and depreciation rate and resulting depreciation expense recommendations made by Mr. Michael J. Majoros, the Ratepayer Advocate's depreciation expert.

The Company's proposed *pro forma* rate base is $648,074,000. *P-36,* HAC-1. The Ratepayer Advocate has made rate base adjustments totaling $33,305,000, resulting in a *pro forma* rate base of $614,769,000. *RA-55* Each of these recommended rate base adjustments is discussed in detail below.

B. Rate Base

1. Cash Working Capital ("CWC")

CWC is an element of rate base and can be defined as monies advanced by the utility's investors to cover expenses associated with the provision of service to the public before those expenses are paid by customers and received by the Company. The Company has performed a lead/lag study which indicates a positive CWC requirement of $56,567,000. *P-36,* HAC-2 and HAC-4. The Ratepayer Advocate proposes a CWC requirement of approximately $45,875,000 based on Mr. Dirmeier's recommended adjustments to certain components of the Company's lead/lag study. *RA-5555,* Sch.16.

a. The Company's Lead/Lag Study Should Reflect The Updated Costs of Capital

In calculating the Company's CWC requirement, Mr Dirmeier made adjustments to several lead/lag components included in the Company's study. Mr. Dirmeier recognized, first of all, that the Company has improperly included the test year unadjusted utility operating income as the "invested capital" in the lead-lag study. The unadjusted income in the test year is not a proper item to be included in pro forma working capital. Instead, the lead/lag study should reflect the costs of capital that are being included in the rate decision. Therefore, the "invested capital" line in the lead - lag study should be adjusted to equal rate base multiplied by the weighted cost of capital. That product is the amount that customers are being required to pay in rates and, accordingly, is the return that should be included in the lead - lag study for working capital purposes.

b. Long-Term Debt Interest and Preferred Stock Dividends Must Be Recognized in The Company's CWC Calculations.

(i) Long-Term Debt Interest

The Company has not recognized the actual lead in the payment of long-term debt interest in its lead/lag study in arriving at its CWC requirement. As the Company actually pays its long-term debt on a semi-annual basis, with an average payment lead of approximately 91 days, this payment lead should be considered in the lead/lag study to determine the Company's appropriate CWC requirement. *RA-50*, p.44.

The rates paid by the Company's customers are set to produce, in addition to other amounts, the sums necessary to pay interest expense to bondholders. Since the Company pays its bondholders twice a year but collects revenues for such bondholder payments on a daily basis, the Company has the use of these funds provided by ratepayers for interest expense payments as working capital during the period between collecting interest payments from customers and making interest payments to bondholders. The Company's ratepayers provide these funds continuously, in a steady stream, and not in a pattern that matches or coincides with the Company's liability for the expense. Ratepayers, not the Company, are correctly entitled to the benefit of these funds collected earlier than needed to pay the Company's interest expense. It is settled regulatory policy that shareholders are not entitled to a return on capital which the shareholders have not provided. *Federal Power Commission v. Hope Natural Gas,* 320 U.S. 591 (1944), *Bluefield Water Works v. Public Service*, 262 U.S. 679 (1923). Accordingly, the actual interest lead should be reflected in the calculation of CWC. *RA-50,* Sch 16.

There have been several Board decisions holding that long-term debt interest should not be included in a lead/lag study. These precedents hold that a zero (0) day lag should be assigned to long-term debt payments because the return on investment is the property of investors when service is provided. *See I/M/O Atlantic City Electric Company*, BPU Docket No. 8310-883, OAL Docket No. 8543-83 (1984); *I/M/O Public Service Electric and Gas Company*, BPU Docket No. 837-620 (1984). However, this position is inconsistent with the manner in which other cash flow items are handled in a lead/lag study. The lead/lag study examines the actual cash flows, not the incurring of an expense or liability, in determining the Company's CWC requirement. Long term debt interest expense should be treated in a similar manner. Net income is the property of shareholders when service is provided. Interest expense is the property of bondholders at the same time. A failure to include long-term debt interest expense in the lead-lag study assumes that long-term debt interest expense is the property of shareholders, which it is not. In exchange for not receiving payment on a daily basis, bondholders impose a higher interest charge on their bonds, which is an interest charge for which customers pay through higher rates. That delay in payments, and the higher interest rate, is a practical consideration, since it would be expensive for the Company to pay bondholders on a daily basis. Nonetheless, equity investors are not entitled to earn a return on funds advanced by bond investors through their willingness to accept semi-annual payments on their bonds, albeit at a higher ratepayer-funded interest rate. That delay in interest payments makes cash available to the utility, but it is non-equity-provided cash that should be reflected in the lead/lag study properly as a reduction in working capital.

Moreover, commissions in other states, such as the Georgia PSC, have held that it is appropriate to include interest on debt and preferred dividends with appropriate payment lags in a lead/lag study:

> As should be abundantly clear, it is error not to include as elements of a lead-lag study the net payments of interest on long-term debts and dividends on preferred stock. These two elements are sources of funds utilized to reduce cash requirements.

Atlantic Gas Light Company, 119 PUR 4th at 404, 408, (1991).

The interest payments to be made to the bondholders are fixed by contract. *RA-50*, p. 44. To refuse to consider the source of CWC from the interest payment lead penalizes the ratepayers who are providing revenues to pay all expenses, including interest expense; and provides a "windfall" return to the common stockholders.

c. Preferred Stock Dividends

Preferred stock dividends should be afforded the same treatment as long-term debt interest. These are contractual payments and the Company is legally obligated to make specified payments on certain dates. In that respect, preferred dividend elements of Atlantic's return resemble other cash operating expenses for which a lead/lag calculation is required. Preferred stock dividends are paid quarterly, resulting in a 45 day expense lead, making it appropriate for inclusion in the Company's lead/lag calculation. *RA-50*, p. 44.

d. CWC Conclusion

In summary, based on the above described approach and based upon the cash operating expenses and taxes recommended by the Ratepayer Advocate in this case, the Ratepayer Advocate recommends a positive CWC requirement of $45,875,000.

2. Pension Liability Adjustment.

Mr. Dirmeier recommended that Your Honor and the Board make an additional adjustment to rate base to reflect the Company's $46,565,000 pension liability at the end of 2002. *RA-50,* p.17. As noted by Mr. Dirmeier in his Direct Testimony, in the Company's last base rate case, the Company proposed a pension expense of $5,635,000. That proceeding was resolved by stipulation so it is not possible to determine exactly the level of pension expense that was included in rates. It is unlikely however that the Company received less than the $3,689,000 proposed by the Division of Rate Counsel[6] in that proceeding.

Notwithstanding that customers were being charged rates that included some level of pension expense in the years 1999, 2000, 2001, and 2002, the Company made no payments to the pension fund during that time. As a result of making no pension payment to the pension trust in the years 1999 through 2002, Atlantic's prepaid pension liability has grown from $9,804,000 at the end of 1998 to $46,565,000 at the end of 2002. During that time frame, the Company recorded $35.3 million of pension expense, although it funded $0 of pension liability. The pension liability on Atlantic's books is an absolute source of funds available to and used by the Company, but which is not reflected as a reduction of rate base in the Company's filing. That is because pension expense is being included in and recovered in rates, but, during that four year period, was not paid.

It is appropriate for Your Honor and the Board to reflect this pension liability as a reduction in rate base rather than to measure the lag in payment and include this calculation in the Company's working capital adjustment. This account reflects amounts collected from customers but not yet paid into the pension fund. While it is known that Atlantic has been collecting pension expense from customers for a substantial period of time without making any

[6] The Division of Rate Counsel is the predecessor agency of the Ratepayer Advocate.

payment to the pension fund, it is not known when those pension expense collections actually will be paid to the fund.[7] Payments to the pension fund are based on actuarial and income tax considerations that change over time. Thus it is not feasible to predict when payments to the fund will be made or when the particular expense to be collected in rates as a result of the current proceeding will be paid into the fund. Thus, it is appropriate to adjust rate base rather than CWC to reflect pension liability.

Indeed, the Company makes similar adjustments to rate base. Atlantic has included in rate base specific balances relating to materials and supplies, customer advances for construction and customer deposits. For example, in addition to the Company's proposed $56,567,000 CWC adjustment to rate base, the Company has included $8,582,000 for Materials and Supplies. *P-35*, HAC-2 [corrected]. The Materials and Supplies account represents the average balance of Materials and Supplies purchased by the Company and held on hand prior to their actual use. And, while it theoretically would be possible to measure a lag between the dates of purchase and use, to do so would introduce a significant element of uncertainty into the lead/lag calculation. It is difficult to determine with any precision when any single purchase or group of purchases for Materials and Supplies will be used to provide service. Thus, by making a separate rate base adjustment, the Company has recognized that the inclusion of Materials and Supplies in CWC would be a large lead, subject to considerable controversy in both measurement and application.

Similarly, it is appropriate to deduct from rate base the Company's pension liability rather than to attempt to measure the lead between the collection of funds and the use of the funds. As with Materials and Supplies, to attempt to include the pension liability account in the

[7] The Company's October 2003 pension contribution was made far beyond the 2002 test year and therefore should be excluded from consideration in this proceeding.

CWC calculation would introduce a significant element of uncertainty in the lead/lag calculation. And yet, this account, which reflects amounts collected from customers but not yet paid into the pension fund, is a significant source of funds and should be reflected in the Company's accounts as such.

In conclusion, these pension expense dollars collected from ratepayers over the past several years but not yet paid into the Company's pension fund provide cost-free funding to the Company. As such, the Company has been able to use this money in any manner it chooses. To ask the Company's ratepayers to pay the Company a return on these cost-free funds provided by ratepayers and used by the Company is improper and should not be condoned by Your Honor and the Board.

3. Other Rate Base Adjustments.

The Company has made certain other adjustments to rate base in this proceeding that go well beyond the Company's 2002 test year. In fact, the Company has included and the Ratepayer Advocate has not disputed more that $28.5 million in plant transfers from January through June of 2003. Additional rate base adjustments proposed by the Company go well beyond this six month period and should be disallowed by Your Honor and the Board. These include adjustments for: interval metering, security costs, residential time of use metering and storm damage costs.

The Ratepayer Advocate acknowledges that the Board has permitted certain post-test year plant in service additions to be reflected in rate base. *Re: Elizabethtown Water Company Rate Case*, Docket No. WR8504330 (hereinafter "*Elizabethtown Water*"). However, this often cited Board decision does not grant the utility the unfettered discretion to include any and all capital expenditures after the Company's chosen test year. To do so would totally invalidate the "test year"concept. Rather, the Board has carefully carved out a narrow exception to allow major adjustments to rate base occurring within six months of the end of the test year which have been carefully quantified through proofs which manifest convincingly reliable data. *Id.* Specifically the Board agreed to consider:

> (b) changes to rate base for a period of six months beyond the end of the test year provided there is a clear likelihood that such proposed rate base additions shall be in service by the end of said six-month period, that such rate base additions are major in nature and consequence, and that such additions be substantiated with very reliable data. *Id.*

Here the Company has proposed changes to rate base that are well beyond the six month post test year period. In fact, the Company is proposing to include in rate base items which had not yet been purchased at the time of the hearing, more than a year beyond the Company's chosen test year. Moreover, some of the Company's proposals are not major in nature and consequence, for example, the proposed security upgrades total $280,000. Furthermore, as discussed below, these proposed adjustments have not been substantiated by reliable data. Indeed, these proposed adjustments to rate base so dramatically fail the *Elizabethtown Water* test that if Your Honor and the Board were to allow these adjustments into rate base, the *Elizabethtown Water* decision will have effectively been overruled.

a. Interval and Residential Time of Use ("TOU") Metering

The Company's proposed inclusion in rate base estimated costs for Interval and Residential Time of Use metering that had not yet incurred, 17 months beyond the test year, violates *Elizabethtown Water*, the matching principle, the "used and useful" principle, as well as just about every other basic tenet of rate making policy in New Jersey. This improper adjustment is discussed in detail in the operating income section of this brief. Moreover, and as also discussed below, the Company's alternate proposal to collect these amounts through the Market Transition Charge violates the Electric Discount and Energy Competition Act. *N.J.S.A.* 48:3-49, *et seq*. ("EDECA").

b. Increased Security Costs

Ratepayer Advocate witness Michael Dirmeier recommended that Your Honor and the Board disallow the Company's claimed capital expenditures for "Security Upgrades." The test year in this case was the calendar year 2002. The Company has included, and the Ratepayer Advocate has not disputed, $28,530,000 in plant transfers from January through June of 2003. The additional inclusion of these Security Upgrades has not been adequately supported by the Company and should not be allowed into base rates. As noted above, the Board in *Elizabethtown Water* allowed post test year adjustments to rate base when the adjustments were within six months of the end of the test year, when the rate base additions were "major in nature and consequence," and were "substantiated with very reliable data." The Company has failed to meet these requirements. The issue of security upgrades is discussed in more detail below in the operating income section of the brief.

c. Storm Damage Costs

As with the Company's other rate base adjustments discussed above, the Company's rate base adjustment for storm damage costs fails the *Elizabethtown Water* test for inclusion into rate base. The Company, in an updated filing dated October 28, 2003, included rate base adjustments for costs incurred as a result of Hurricane Isabel which hit New Jersey on September 18, well beyond the six month window allowed by the Board in *Elizabethtown Water*. Based on admittedly estimated costs, the Company sought to include $1.7 million in rate base for costs "related to its T&D blanket insurance deductible." *P-35*, p. 8. The Company's Storm Damage Costs are discussed in more detail below, in the operating income section of this brief.

d. Summary

In summary, the above post test year plant additions claimed by the Company show a lack of appreciation for New Jersey rate making procedures and policy. The rate base adjustments requested are well beyond the end of the test year and do not meet the Board established requirements for inclusion as post test year adjustments. Amounts are estimated and evidentiary support for even these estimated amounts is almost non-existent. In New Jersey, the Company bears the burden of proof. Clearly the Company has chosen not to shoulder that burden in this instance.

C. Operating Income

THE APPROPRIATE *PRO FORMA* OPERATING INCOME AMOUNTS TO $50,938,000 WHICH REPRESENTS A $9,395,000 INCREASE OVER THE COMPANY'S PROPOSED *PRO FORMA* OPERATING INCOME OF $41,543,000.

1. Revenue Adjustments

a. Weather Normalization

The Company in its updated filing adjusted test year operating income to reflect normal weather conditions. The Company contended that as of December 31, 2002, the actual test year sales were 160,243,000 kWh above weather normal. Based on this determination, the Company decreased test year operating income by $2.787 million.

Ratepayer Advocate witness Michael Dirmeier determined that the Company had used 15 years of historical data to determine normal weather. Mr. Dirmeier noted that this was inconsistent with the prior Atlantic base rate case, in which the Company used thirty years weather normalization, and that the Company had failed to justify this deviation from past practice. When asked to support this change, the Company responded that the use of a 15 year weather normalization was current Conectiv policy. The Company admitted that "[n]o studies were undertaken" by the Company to establish that a 15 year weather normalization better captured the warming trend of degrees than the previously used 30 year weather normalization. *RA-50*, p. 34 citing the Company's response to RAR-RR-71(G).

Subsequently, in rebuttal testimony, the Company claimed that it did have such a study.

> Q. Has Conectiv performed any studies to determine if 15-years, 20-years, or 30-years of data provide a better estimate of current expected weather?

> A. Yes. The data does show that a trend-line running through 30-years of HDD data, as measured at the Atlantic City Airport, clearly has a downward slope. Thus, utilizing 15-years of data more closely captures this warming trend.

P-36, p. 32.

As noted by Mr. Dirmeier, the belated trend line relied upon by the Company to support its use of 15 year weather normalization did not provide the claimed support. In fact, as Mr. Dirmeier noted, the trend line was a simple linear regression analysis with a downward sloping trend line. As Mr. Dirmeier explained, over 90% of the change in heating and cooling days reflected in the trend line was explained by variables not reflected in the trend line.

At the time of filing his Direct Testimony, Mr. Dirmeier was unable to calculate a 30 year weather adjustment. Subsequently, Mr. Dirmeier determined that he could utilize data provided by the Company to develop a weather normalization adjustment based on approximately 28 years of data. Mr. Dirmeier's recommended weather normalization adjustment is a decrease in operating income of $2.329 million. *RA-51*, p. 30.

Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board adopt the proposed near-thirty year weather normalization adjustment. This adjustment is consistent with prior Board Orders. The Company has provided no support to justify the use of a 15 year weather normalization and has failed to cite any government agency or any state commission that supports the use of 15 year weather normalization. Conversely, as pointed out by Mr. Dirmeier, Congress requires the National Oceanic and Atmospheric Administrations' ("NOAA") National Climatic Data Center to establish and record climate conditions in the United States. That center uses 30 years as the basis for normal weather. *RA-51*, p. 31. The Energy Information Administration of the U.S. Department of Energy ("EIA") utilizes a 30 year standard in its reports. The EIA's Residential Demand Module also uses a 30 year standard for normal weather. *Id*. And, in Delaware, in Docket No. 94-22, Delmarva stipulated to the use of a weather normalization methodology that relied on 30 year data from NOAA for determining gas rates. On October 7, 2003, in Delaware Docket No. 30-127, Delmarva again agreed to utilize 30 years data in filing its next base rate case for natural gas.

In conclusion, the Company has chosen to calculate its weather normalization on a 15 year basis without any reasoned explanation and without any credible analysis. The Company has provided no evidentiary support in the record upon which Your Honor and the Board could justify such a change in Board policy. Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board adopt the Ratepayer Advocate's recommended 30 year weather normalization adjustment, a decrease in operating income of $2.329 million.

2. Expense Adjustments

a. Depreciation Expense

Mr. Dirmeier made three adjustments to the Company's proposed depreciation expense. The adjustments to depreciation rates will be discussed below in Section IV. Adjustments to reflect depreciation on year end plant and the adjustment for changes in deferred tax expense and reserve consistent with the adjustment to annualized depreciation expense will be discussed below.

Mr. Dirmeier adjusted the Company's proposed depreciation expense to reflect the recommendations of Ratepayer Advocate witness Michael Majoros. This re-calculation of the Company's proposed depreciation expense produced a reduction in depreciation expense of $11,438,000. *RA-55*, Sch.5,p.1.

In its filing, the Company proposed an adjustment to annualize depreciation expense based on test year-end plant in service. This adjustment reduces operating income by $1,226,000 and reduces rate base by $2,073,000. Mr. Dirmeier also applied the Ratepayer Advocate recommended depreciation rates to the test year end plant balances. *RA-55*, Sch.5. p. 2. This calculation reduces the Company's income by $292,000 and increases the rate base reduction by $507,000. *Id.*

b. Deferred Tax Adjustment

The Company has claimed that the level of book depreciation expense, based on the December 31, 2002 level of Plant in Service, at current book depreciation rates, will be higher than the test year depreciation expense. *P-35*, p. 9. The Company then made an adjustment to depreciation expense to reflect in operating expenses the additional level of depreciation expense that will occur during 2003. This adjustment resulted in an $1.226 million decrease to test year operating income. What the Company has failed to consider however is that not only will book depreciation be higher, but tax depreciation expense, deferred tax expense and deferred tax reserve will also increase. The appropriate, complete adjustment recognizes all of these changes, not just a few of the changes as reflected in the Company's proposed adjustment.

Generally, the Company has correctly carried through the effect of an adjustment to book depreciation expense to deferred tax expense and reserve associated with the change in book depreciation. For example, in the Company's Interval Metering adjustment, shown on schedule HAC-6, the Company properly incorporated the effect of changes in deferred tax expense and reserve associated with the change in book depreciation expense. Similarly, in the Company's proposed adjustments for Additional Security costs (HAC-7), Residential Time of Use Metering (HAC-19) and Storm Damage (HAC-20), the change in book depreciation expense is properly carried through to deferred tax expense and reserve. *P-36*. In contrast, with respect to the depreciation expense annualization adjustment on Schedule HAC-8, which is the largest depreciation adjustment proposed by Atlantic and therefore the adjustment that would have the largest effect on deferred tax expense, Atlantic has failed to incorporate an adjustment to either deferred tax or reserve.

Mr. Dirmeier reasoned that there was no basis to support different treatment for the depreciation annualization adjustment. When asked to explain why the depreciation annualization adjustment did not include adjustments for deferred income taxes associated with the proposed annualization, the Company replied:

> The Company's adjustment is calculated to be consistent with a prior Board Order, which recognized a change in test year depreciation expense.

RA-50, p. 8, Exhibit A, the Company's response to RAR-RR-146

Attached to the discovery response was the first and last page of the Board Decision and Order in BPU Docket No. 822-116, a rate base schedule and an operating income schedule. The third page to the attachment was a handwritten Book Depreciation schedule.

The Company's claim that the adjustment is "consistent with a prior Board Order" is a bit of a stretch. Perhaps a better way to put it would have been "consistent with the way the Company calculated a change in depreciation expense in a prior rate case." Certainly the issue of revisions to the Company's depreciation <u>rates</u> was discussed by the ALJ in the Initial Decision and by the Board in the Decision and Order. However, there was no discussion regarding the failure to consider the effects of the depreciation expense adjustments on deferred tax and reserve. Certainly there was not explicit Board approval of this accounting. And, while the rate base and operating income schedules were attached to the copy of the Board Order found in the

Ratepayer Advocate's Library, the handwritten Book Depreciation schedule provided by the Company in response to RAR-RR-146 was not found. It is unclear from the Company's response exactly what this document is. But, based on the information provided in the Board Order and the rate base and operating income schedules attached to that Board Order, there is no way to tell how depreciation expense was calculated in that proceeding. Nor is there anything in the Company's response that substantiates different treatment for different depreciation adjustments, wherein some depreciation adjustments properly take into account changes in deferred taxes and others do not.

The failure to adjust the deferred tax and the reserve accounts is not appropriate when making depreciation expense adjustments. The Company has no reasoned support for this omission. The Company does not claim that the Ratepayer Advocate's adjustment is faulty, that there is some legal or financial reason not to make this adjustment. The Company cites no accounting rule in support of its position. The Company merely alleges that it was done this way in 1982 and nobody objected.

Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board direct the Company to properly incorporate depreciation expense adjustments into the deferred tax and reserve accounts. This adjustment results in a rate base deduction of $507,000.

c. Pension Expense

Atlantic is seeking to include $5,167,000 of pension expense in distribution O&M in this proceeding based on 2003 budget projections. *P-35*, HAC 15[8]. This is a 26% increase over the $4,087,000 of pension expense charged to actual 2002 distribution O&M expense. The Company, in its initial filing did not explain why the actual test year pension expense was not the appropriate expense for ratemaking purposes. Company witness Herbert Chalk simply states: "This adjustment reflects the change of pension expense from the 2002 level to 2003." *P-34*, p.14. Thus, this 26% increase over the $4,087,000 of pension expense charged to actual 2002 distribution O&M expense is seemingly based on the premise that it is generally accepted BPU ratemaking policy to replace actual test year results with future budgeted amounts. The Company made this adjustment with no explanation as to why this adjustment was necessary or appropriate and with no attempt to justify the deviation from the Company's proposed test year.

Moreover, the Company's underlying support for the 2003 budgeted amount is seriously flawed. The Company based this budgeted amount on:

> . . . projected adverse loss experience in 2002 and a projected lower estimated return on assets in 2003. This was due to a projected continuation in the decline of market returns and interest rates as experienced during 2001 and 2002.

RA-50, p. 16 (citing the Company's response to RAR-RR-35 (f))

As noted in Mr. Dirmeier's testimony, the market was up, substantially, in 2003.

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[8]

	ACE	CRP	Total
Year 2003 budget	$12,510	$8,600	
Percent recorded to ACE	100%	35.47%	
Percent to O&M	60.40%	87.00%	
Distribution Allocation	50.61%	50.61%	
	$3,824	$1,343	$5,167

	12/31/02	12/01/03	% change
Dow Jones Industrial	8341.63	9899.05	18.67%
Dow Jones Utility	215.18	252.80	17.48%
S&P 500	879.82	1069.84	21.60%
NASDAQ Composite	1335.49	1989.82	49.00%

Thus, the Company's prediction of continuing declines in market returns is not supportable in the face of actual market events.

The Board has consistently rejected adjustments to expenses that are not sufficiently "known and measurable" for inclusion in rates. The Board in *Elizabethtown Water* allowed the Company "to make a record with regard to (a) known and measurable changes to income and expense items for a period of nine months beyond the test year . . . " The Board directed:

> 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 forecasing techniques reflected in the record.

See also, I/M/O The Petition of Elizabethtown Gas, BPU Docket No. GR88121321 (The Board agreed with the ALJ's finding that certain post test year O&M adjustments "were not sufficiently supported in the record."). Surely, the policy that prohibits adjustments that are not sufficiently known and measurable for inclusion in rates prohibits adjustments, such as that proposed in this case by the Company, that are outright incorrect.

This adjustment based on the flawed assumptions that budgeted amounts are the proper basis for setting the Company's rates and that market returns will continue to decline well into the future does not pass the "known and measurable" test established by the Board for post test year adjustments to expenses. The Company is attempting to include in rates a level of pension expense that is overstated because it is based on a false assumption. Your Honor and the Board should adopt the Ratepayer Advocate's recommendation that the Company's actual test year pension expense be included in rates; there is no support in this record to do otherwise.

Moreover, Your Honor and the Board should be cognizant that rates are not being set solely for next year, but for the indefinite future. Here, pension expense is being proposed to go up on the basis of a severely faulty assumption. Embedding that implausible and wrong assumption in permanent rates means that rates for the indefinite future would contain excessive pension expense. Those rates would assume that not only is the market going to decline in 2003, which it did not, but that it would further decline in 2004, 2005, and for each year for the life of the rates in this proceeding.

d. Incentive Compensation

The Ratepayer Advocate recommends that Your Honor and the Board disallow the $1.7 million in incentive compensation costs claimed by the Company. *P-35*. The Company has failed to provide adequate documentation of the various plans for which it is claiming cost recovery. Furthermore, the limited information provided indicates that the Company's incentive compensation plan overwhelmingly rewards the achievement of certain financial goals. Because shareholders receive the benefit from the attainment of these financial goals, shareholders should pay the costs. Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board follow long established Board precedent and exclude from rates the $1.7 million associated with the Company's incentive compensation plans.

As a preliminary matter, it should be noted that, at the hearing, it was revealed that the document that the Company provided in response to Staff discovery request S-CREV-117, entitled the *Conectiv Inc. Incentive Compensation Plan* was not one of the incentive plans the Company was proposing to include in rates. Why the Company provided, without protest or explanation, a confidential document that is irrelevant to any issue in this proceeding is puzzling, especially in light of the Company's refusal to provide transmission data, on the basis that it was not relevant, when in fact, transmission data was relevant. The Company was aware that the Ratepayer Advocate was relying on this document, it is quoted extensively in the testimony of Ratepayer Advocate witness Michael Dirmeier, and yet the Company made no attempt to rebut or correct this testimony until the hearing.

At the hearing, Mr. Wathen testified that this plan

> was something that is offered to ACE officers, and, to my knowledge, no cost associated with this particular plan has been included in the test period for recovery.
>
> T1100:L14-18.

Similarly, the Company's response to RAR-SQ-13, entered into evidence as RA-48, provides evidence regarding plans seemingly not included in the Company's requested $1.7 million adjustment for their Incentive Compensation plan.

> A The response to, that is reflected in Exhibit RA-48, appears to - - it is very similar to the types of incentives included in the management variable incentive plan, although this is a more narrow plan. Apparently, this does include MVIP.
>
> Q. It includes what? I'm sorry I didn't understand you.
>
> A. MVIP. It is the very last page of the exhibit. I didn't get that far. Yes, a portion of this, at least, is included in the 1.7 million that is being sought, which is listed again in the response to S-CREV-143 as salaries, incentives, MVIP, the description being the management variable incentive plan. So that portion, or at least a portion of this related to Atlantic Electric, does appear to be included.
>
> T1101:L12-16.

It is unfortunate that the Company chose to provide copies of incentive compensation plans not relevant to this proceeding. However, as Mr. Wathen testified that all the Company's plans "have the same framework of drivers", any discussion of the MVIP will, by Mr. Wathen's admission, apply to the Company's other plans as well. *P-39*.

i.) Incentive Compensation Plans Are Within Sole Discretion of The Company's Management.

The Company's MVIP expressly directs that "[t]he Board of Directors must approve all incentive compensation plans each year." T1104:L15-21. Whether or not there will be incentive payments, how much will be distributed, and to whom, is determined solely by the Company's management. The Company's management has full authority to set the targets and to determine whether or not the Company will be making incentive payments. The awards are totally discretionary. Thus, the Board could authorize the inclusion of a set level of incentive compensation payments into rates only to have the Company make no incentive payments to employees and allow the money to flow through to investors thereby augmenting the Board authorized return on equity. Moreover, while it is true that expenses after test periods differ from those in the test period, a totally discretionary expense is, by definition, not necessary to the provision of utility service.

ii.) The Stated Objectives of the Incentive Compensation Plans Do Not Place Ratepayer Interests on an Equal Level With Shareholder Interests

The MVIP sets four corporate performance measures and goals, earnings, utility O&M expense, construction budget and customer satisfaction. These performance measures are heavily weighted toward the achievement of financial goals, the weighting for the earnings part of the corporate measure is 50%, for the utility O&M expense the weighting is 15%, for the construction budget measure the weighting is 15% and for the customer satisfaction measure the weighting is 20%. T1105:L16 - T1106:L4. Thus, 80% of the performance measure is based on the achievement of financial goals.

At the hearing, in an attempt to show that ratepayers benefit from incentive compensation plans, the Company cited a goal called "direct O&M per customer." When asked by counsel if he could explain what that was, Mr. Wathen replied:

> **A.** Yes. We had a goal to manage O&M on a per customer basis. It is just another way to measure it tied to the number of customers that you are trying to serve.
>
> Q. And if you achieve that goal, what would that tend to do to the test period expenses in that case?
>
> A. The cost per customer would be relatively lower.
>
> Q. And if you failed to meet that goal, what would be the results?
>
> A. The cost to customers for O&M expenses would be relatively higher.
>
> Q. So would you state then that this is a goal that either benefits the customers or has no effect on the customers?
>
> A. I think the goal benefits the customers.

T1119:L22 ; T1220:L13

What Mr. Wathen neglected to explain is how, outside a rate case, the reduction in O&M expense gets flowed back to benefit ratepayers. It does not. In fact, it is the shareholders who benefit in this instance. If O&M expense goes down, profits go up. If O&M expense goes up, incentive compensation payments are not made and the money is flowed through to shareholders. Indeed, the inclusion of incentive compensation plans into base rates is a win-win for the Company's shareholders. The money for incentive compensation payments is received from ratepayers. If the established financial goals are met, shareholders benefit through increased profits and management benefits through incentive compensation payments. If financial goals are not met, shareholders still benefit. The Incentive Compensation dollars collected from ratepayers but not distributed are still available in some form for distribution to shareholders.

Moreover, Mr. Wathen's testimony assumes that an incentive compensation plan actually results in the reduction of expense. The Company made no effort to establish that relationship between incentive compensation and expense. He used the example of a lineman. The Board is asked to conclude that some small amount of incentive compensation that a lineman might receive will cause the lineman to be more careful, when concern over potential electrocution and death seemingly is insufficient for the lineman to use care in his work.

iii.) Established Board Policy is to Disallow Incentive Compensation Expenses in Base Rates

The Board has an established policy of disallowing incentive compensation expenses in base rates. In the Board's Final Decision and Order in *I/M/O the Petition of Jersey Central Power & Light Company for Approval of Increased Base Tariff Rates and Other Changes for Electric Service and Other Tariff Revisions*, BPU Docket No. ER91121820J (February 25, 1993), the Board disallowed all of the costs associated with the utility's incentive compensation plans. The Board stated:

> 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 or 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. Accordingly, we HEREBY MODIFY the Initial Decision and DENY from inclusion in rates the entire test year compensation expense of $554,000.

More recently in the Middlesex Water Company base rate case, the Board reaffirmed this decision and denied the water utility's request to include incentive compensation expense in its rates. *I/M/O the Petition of Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes*, BPU Docket No. WR00060362 (June 6, 2001). In rejecting the Administrative Law Judge's recommendation to share incentive compensation costs 50-50 between ratepayers and shareholders, the Board agreed with the reasoning in the JCP&L order, and noted that, "[t]he language in the Board's JCP&L 1993 Order is especially appropriate today when consumers are still faced with increasing energy costs, as well as other increased costs."

Accordingly, as the Company's shareholders are the primary beneficiaries when the Company achieves overall performance targets, the shareholders, rather than New Jersey ratepayers should pay these awards. Under this proposal, shareholders will remain protected from excessive incentive payments becoming a financial drain on shareholder wealth because the Company's plans require that a minimum earnings threshold be achieved before any payments are made. The Ratepayer Advocate respectfully requests that Your Honor and the Board disallow Atlantic incentive compensation expenses for rate making purposes.

e. Interval Metering

In its original filing, the Company adjusted its proposed rate base to include expected distribution plant transfers to Plant in Service through June 30, 2003. Included in this adjustment were costs to install interval metering at 110 Commercial and Industrial ("C&I") premises served under the Company's AGS-Primary rate; costs to install interval metering on smaller C&I customers; and costs to install interval meters on a 500 premise sample of all remaining customers served on the AGS-SEC and MGS-SEC rate classes. The Company included in its Distribution Plant the estimated cost to install this metering equipment:

Large Primary C&I BGS-CIEP meters	$ 123,000
Large Secondary C&I BGS-CIEP meters	$1,048,000
Small C&I Class Load Survey	$ 550,000
	$1,721,000

P-34, HAC-6.

The Company increased these projected amounts in its Rebuttal filing:

Large Primary C&I BGS-CIEP meters	$ 177,000
Large Secondary C&I BGS-CIEP meters	$1,508,000
Small C&I Class Load Survey	$ 791,000
	$2,476,000

P-36, HAC-6.

Ratepayer Advocate witness Michael Dirmeier recommended that Your Honor and the Board exclude these projected amounts from rate base. As Mr Dirmeier noted, the Company is attempting to include in rate base as "plant in service," meters that have not been installed 17 months after the end of the test year. During discovery, the Company admitted that as of November 30, 2003, no additional meters had been either installed or purchased. In fact, there have been no capital expenditures at all for the Company's interval metering projects. And, at the hearing on April 5, 2004, Company witness Herbert Chalk testified that "to date the

Company has not incurred the cost related to interval metering as originally expected . . . " T 1030:L12-14. For such speculative amounts to be included in rate base before the costs are actually incurred and before the proposed meters are "used and useful" turns New Jersey rate making procedure and policy on its head. Your Honor and the Board should disallow the Company's attempt to include in rate base costs which have not yet been incurred.

In addition to the rate base adjustment discussed above, the Company initially included \$986,000 in O&M expense for interval metering. *P-34*, HAC-6. The Company subsequently lowered this projected amount to \$601,000. *P-35*, HAC-6. The only support for the inclusion of these amounts by the Company is that the Board has directed the migration of certain large customers to the BGS-CIEP rate. The Company did concede in rebuttal testimony that the only Board mandated change that has occurred to date is the migration of the certain large customers to the BGS-CIEP rate effective June 24, 2004. The Company conceded that the only Atlantic customers of this size were already in the BGS-CIEP rate class and that therefore the "[a]ctions of the Board to-date have not resulted in the mandatory expansion of the CIEP class as originally projected by the Company." *P-36*, p.26

The Company here has seemingly ignored the fact that to-date, no additional costs have been incurred for interval metering. The Company offers no precedent for pre-spending rate recovery, it merely complains that because interval metering will provide no benefit to the Company, the Company is entitled to recovery based on projections and expectations. This is not rational rate making and should not be adopted by Your Honor and the Board.

In a last ditch effort, perhaps in recognition of the futility of proposing to include in rates costs that have not been incurred, the Company requests that the Board permit recovery of these costs through the Market Transition Charge. The Company justifies this alternate arrangement by saying that the MTC is appropriate because interval metering benefits all customers and all customers pay the MTC. The Company's proposal would turn the MTC into a general repository for any charge that for some reason is not properly included in base rates. The Company appears to be saying that rather than wait until the costs are incurred, reviewed and properly allocated through cost of service and rate design analysis, just include them in the MTC and let the Company collect without the hassle of a rate case.

The Company's proposal to collect these not yet incurred metering costs through the MTC is not only inappropriate but also illegal. The MTC was established as a charge imposed on ratepayers "for a limited duration transition period to recover stranded costs created as a result of the introduction of electric power supply competition . . ." *N.J.S.A.* 48:3-51. The category of costs properly included in this charge include:

> (1) Utility generation plant stranded costs;
> (2) Stranded costs related to long-term and short-term power purchase contracts with other utilities;
> (3) Stranded costs related to long-term power purchase contracts with non-utility generators; and
> (4) restructuring related costs. *N.J.S.A.* 48:3-61(a).

The above listed costs must otherwise be unrecoverable as a direct result of the implementation of retail choice, *N.J.S.A.* 48:3-61(b), and, generally, stranded costs that may be eligible under (1) or (2) above "must have been committed to by the utility and included in rates through the conclusion of the utility's most recent base rate case prior to April 30, 1997." *N.J.S.A.* 48:3-61(d). Thus, the Company's proposal to collect interval metering costs through the MTC violates EDECA and cannot properly be authorized by Your Honor and the Board.

f. Residential Time of Use ("TOU") Metering

In its October 2003 update, the Company included in rate base an additional $1,134,000 for residential time of use meters. The Company contended that the Board-directed establishment of residential TOU rates would require the installation of new TOU meters for all customers choosing the TOU rate class. The Company does not contend that it has spent any money on time of use meters for the residential class, only that it may have to spend in the future. In fact, at the April 5, 2004 hearing, the Company's witness testified "As of this date we have not incurred any time of use metering costs for residential customers." T1030:L21-23

As discussed above, the Board's mandate in *Elizabethtown Water* does not provide for inclusion into rate base estimated costs that may be incurred seventeen months beyond the end of the test year. Indeed, the single most relevant fact in utility ratemaking - the fact that the cost has been incurred - appears almost irrelevant to the Company. The Company's sole concern appears to be that if these costs are not recovered immediately, shareholders will be subsidizing customers. *RA-51* (citing the Company's response to RAR-RR-200(C))

It is not the Ratepayer Advocate's position that the Company should be denied recovery of these types of costs in rates. It is the Ratepayer Advocate's position that these costs should be treated no differently that other utility capital and O&M expense included in a utility's rates. These costs, no matter how mandated they are, have not yet been incurred and therefore are not eligible for inclusion in base rates. Further, as discussed above, the Company's proposal to collect these amounts through the MTC violates EDECA.

g. Security Cost Adjustment

The Company has proposed, once again, to disregard the filed test year and to add into rates security costs that will be incurred in 2003. Despite the mandates of *Elizabethtown Water* the Company has gone well beyond the end of the 2002 test year and has failed to provide any reliable or convincing data to support this expansion of the test year. The only evidence supporting these costs is Mr. Chalk's Direct Testimony:

> The Company will incur additional security costs during 2003 in excess of the actual security costs included in the test year. This adjustment quantifies the increase in security related Operating and Maintenance expense from 2002 to 2003 as well as anticipated 2003 security related capital investments. This adjustment is summarized on Schedule HAC-7 and results in a $0.077 million decrease to test year operating income.

The Company's original Schedule HAC-7 merely provides, without explanation, a listing of amounts:

Operating Income	
O&M expense	
IT O&M costs	$190,000
Sunguard Costs	(79,000)
Total O&M	$111,000
Rate Base:	
Plant in Service	
Security Upgrades	$340,000
Security Central	150,000
Total Plant in Service	$490,000

P-34, p. 10, HAC-7

Similarly, in Mr. Chalk's October update, he states:

> The Company will incur additional security costs during 2003 in excess of the actual security costs included in the test year. This adjustment quantifies the increase in security related Operating and Maintenance expense from 2002 to 2003 as well as anticipated 2003 seurity related capital investments. This adjustment is summarized on Schedule HAC-7 and results in a $0.075 million decrease to test year operating income.

And, again, HAC-7 provides only a listing of amounts, this time different amounts:

Operating Income	
O&M expense	
IT O&M costs	$196,000
Sunguard Costs	(79,000)
Total O&M	$117,000
Rate Base:	
Plant in Service	
Security Upgrades	$280,000
Security Central	-
Total Plant in Service	$280,000

P-35, p.7, HAC-7

Thus, without any supporting testimony and without any explanation, IT O&M costs have increased and Security Central, previously a known and measurable adjustment costing $150,000, has vanished.

The Company's proposed adjustments in the October 2003 filing are based on six months actual and six months projected amounts. The projection for July 2003 was $177,000 or almost 40% of the total annual amount proposed. And yet, the actual expense for July was only $27,000. Thus, the projection that Atlantic filed in October included a July projection, at a time when July actuals should have been known, that was overstated by over 500%. *RA 50,* p. 32

The Company has gone well beyond the end of the test year in this proposed adjustment and yet has not attempted to adequately explain or document these proposed post test year additions. When asked to identify for the record what Sunguard is, Company witness Herbert Chalk replied:

> A. Sunguard is, I guess the best way to describe it is it is a disaster recovery consulting group that looked at our disaster recovery systems during 2002 and it was projected that in 2003 that there were additional costs related to Sunguard which did not occur, and so what we did is we reduced those costs by the Sunguard cost that we would not incur in 2003.

T981:L5-12

Why the Company is deducting costs that did not occur from projected costs is unclear. Did the 2002 "actuals" include $79,000 of 2003 projected costs that now must be deducted? Were the Sunguard costs included in some other 2003 account? Without more information regarding what security costs the Company is proposing to recover, these 2003 projected costs should not be allowed in rates. Indeed, the Company knew, based on Mr. Dirmeier's testimony that these amounts were disputed and yet failed to provide either through rebuttal testimony or at the hearings additional information regarding these security upgrades. Clearly the *Elizabethtown Water* standard has not been met and these amounts should be disallowed by Your Honor and the Board.

h. Storm Damage Expense

As with the Company's other rate base adjustments discussed above, the Company's rate base adjustment for storm damage costs fails the *Elizabethtown Water* test for inclusion into rate base. The Company, in an updated filing dated October 28, 2003, included rate base adjustments for costs incurred as a result of Hurricane Isabel, which hit New Jersey on September 18, 2003. Based on admittedly estimated costs, the Company sought to include additional maintenance costs predicted to exceed $1.8 million and $1.7 million in rate base for costs "related to the insurance deductible." *P-35*, p. 8. The Company promised to update this adjustment "as the actual costs are finalized." In rebuttal testimony, Company witness Herbert Chalk testified that: "[t]he actual costs incurred by Atlantic as a result of Hurricane Isabel are now known. I have incorporated the actual costs in the Hurricane Isabel adjustment presented on Rebuttal Schedule HAC-20." *P-36*, p. 4.

In his Direct Testimony, Ratepayer Advocate witness Michael Dirmeier recommended that Your Honor and the Board disallow this adjustment. Mr. Dirmeier noted that the Company had failed to meet its burden of proof in this matter, that the Company had merely stated that because there was a storm, the Company incurred extra costs and therefore should be compensated for these costs. Indeed, HAC-20 does not specify where the money was spent, it only lists a lump sum amount for storm related O&M costs and $1.699 million allocated to "Distribution Plant in Service." As noted above, the Board in *Elizabethtown Water* allowed post test year adjustments into rate base six months beyond the test year when such additions are "major in nature and consequence," and are "substantiated with very reliable data." The Board subsequently re-affirmed this standard:

> The Board FINDS that the company did not support its post test year estimates with construction budgets, work orders or other reliable data . . . . The Company's testimony and schedules that are in the record do not provide sufficient reliable specific data as to the projects it considers major in nature nor the dollars associated with such projects. In addition, the Company did not supply progress reports or other reliable data in support of its requested post test year adjustments. Therefore, the initial Decision is HEREBY MODIFIED to exclude said adjustments. *Elizabethtown Gas Base Rate Case,* BPU Docket No. GR88121321 (1/18/90) (hereinafter "*Elizabethtown Gas*.").

In this case, the proposed rate base adjustment is well beyond the six month post test year window the Board has allowed for rate base additions. Further, the Company has provided no reliable date to support the Company's claimed rate base adjustment of $1.7 million dollars. The "very reliable data" in this instance consists of the Company's Supplemental Testimony, filed ten months <u>after</u> the end of the Company's chosen test year, saying "[t]he adjustment also requests rate base inclusion of the capital costs related to the insurance deductible" and in Rebuttal Testimony filed more than one year beyond the test year, a schedule showing $1.699

million adjustment to "Distribution Plant in Service." At the hearing, the Company witness testified:

> Well, the capital expenditures actually represent the deductibles for our insurance that we have related to capital property, storm damage of our property.
>
> The deductible, which is five million dollars in total, was allocated between Atlantic and Delmarva based on the total capital repairs or capital costs that were incurred for each utility, so we are just seeking recovery of the deductible cost related to our insurance.

T1032:L25 - 1033:L1-9.

With little information regarding total capital costs incurred, Your Honor and the Board cannot be expected to effectively review these capital expenditures and the associated cost allocation. Sufficient information should have been provided at the time the Company made the claim for the recovery of these costs. The Board's *Elizabethtown Water* standard precludes this $1.699 million addition to rate base.

Similarly, there is little in the record to support the claimed $1.5 million increased O&M expenses. The Company's response to RAR-RR-183, entered into evidence as S-21, was not provided until March 4, 2004, more than a year after the 2002 test year. The untimely provision of this information precluded careful review. As noted above, if the Company intended to include these expenses in the Company's rates, expenses that were incurred nearly nine months past the end of the test year, the Company has the obligation to provide this information in a timely manner.

> It must be emphasized that rate making is not an adversary proceeding in which the applying party needs only to present a *prima facie* case in order to be entitled to relief. There must be proof in the record not only as to the amount of the various accounts but also sufficient evidence from which the reasonableness of the accounts can be determined. Indeed, *R.S. 48:2-21(d)* specifically provides that "The burden of proof to show that the increase, change or alteration [in rates]

> is just and reasonable shall be upon the public utility making the same." Lacking such evidence, any determination of rates must be considered arbitrary and unreasonable.

Public Service Coordinated Transport, 5 *N.J* 196, 219 (1950)

The Company has requested post test year adjustments to rate base that go well beyond the six month window allowed in *Elizabethtown Water*. The Company also failed to demonstrate through carefully quantified proofs which manifest convincingly reliable data that the costs were "prudent and major in nature and consequence." *Elizabethtown Water*. Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board hold the Company to the mandates of *Elizabethtown Water* and *Public Service Coordinated Transport* and disallow recovery of these lately incurred storm damage costs.

i. Lobbying and Advertising Expense

The Company conceded, in its October filing, that $331,000 of Atlantic's lobbying expense had been "misclassified and included in utility operating expenses." *P-35*, p.14. The Company accordingly removed from operating expense $242,000 which had been allocated to the electric distribution function. *Id*., HAC-21. However, the Company has failed to remove from operating expense that portion of its Edison Electric Institute ("EEI") dues used to fund EEI Legislative advocacy and EEI advertising expenses claiming that the Company merely pays dues to EEI to receive the benefits of EEI membership and that the "[n]either the Company nor any of its employees participates in any advertising or lobbying activities of EEI." *P-36*, p.37

It has long been Board policy in this state to exclude from operating expense that portion of EEI dues associated with lobbying and advertising expense. As far back as 1984, the Board concluded:

> [T]he staff position to disallow institutional or image advising [sic] especially related to

> expenses paid to the Edison Electric Institute (EEI) is the proper treatment. Petitioner is free to advertise to enhance its image. Petitioner is free to participate in opinion advertising by EEI. However, such expenses are appropriately charged to the corporation and not the ratepayer.

I/M/O the Petition of Rockland Electric Company, BPU Docket No. 839-790 (August 6, 1984).

Subsequently, the Board expanded this directive to include lobbying expenses:

> We ADOPT the position of Staff concerning the exclusion of the portion of Edison Electric Institute dues which reflect lobbying expenses. We do not believe that this is an appropriate expense to impose on ratepayers.

I/M/O the Petition of JCP&L, BRC Docket No. ER91121820J (June 15, 1993).

Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board exclude from operating expense $48,000, that portion of Atlantic's dues paid to EEI that are associated with advertising and lobbying. *RA- 50*, Sch. 14. Atlantic's lobbying and advertising, no matter how indirectly performed through EEI, is still lobbying and advertising and should not be paid for by ratepayers.

j. Postage Rate Increase

The Company has claimed a $107,000 increase in operating expense due to a 3.5 cent increase in the postage rate for bulk mailing that went into effect on July 1, 2002. The Company calculated this amount by multiplying the customer counts for the months of January through June 2002 by the rate increase. However, during discovery the Company admitted that it sends out fewer bills than it has customers. Therefore, Atlantic's adjustment is overstated by the difference between customer bills and customer counts.

Ratepayer Advocate witness Michael Dirmeier corrected this calculation. Mr. Dirmeier looked at actual customer bills and customer counts for each month of 2002. He then calculated, for each month, the monthly postage per bill and postage per customer. A comparison of the first six months of 2002, prior to the postage increase, to the last six months of 2002, indicates that, in fact, the postage per bill increased in the second half of 2002 by 11.5%. The postage per customer increased in the same time period by 11.9%. Based on that determination, Mr. Dirmeier calculated the appropriate adjustment by increasing the first six months of the test year by the average of the actual increases of 11.5% and 11.9%. Mr. Dirmeier's adjustment reduces the Company's revenue requirement by $11,000.

k. Interest Synchronization

Ratepayer Advocate witness Michael Dirmeier's adjustment for interest synchronization is similar to the Company's proposed interest synchronization adjustment except that Mr. Dirmeier includes short term debt and the capital structure and cost recommendations reflected in the testimony of Ratepayer Advocate rate of return witness Matthew Kahal. This adjustment increases the Company's operating income by $667,000.

D. Summary

The Company disregards the test year concept, the matching principle, the standard of used and useful and just about every other basic, long standing rate making principle in this State. The Company has proposed adjustments that go well beyond the test year and has based future rates on inaccurate projections and incomplete documentation.

When Atlantic first filed this case, it sought a base rate increase of $63,353,000. That requested increase was based on nine months actual and three months' projected data. When the Company filed its 12 & 0 update, things had changed enormously. The rate increase sought in the updated filing was $36,822,000. The majority of the $26.5 million reduction in claimed revenue requirement was due to the replacement of forecast information with actual data. Plainly, the 2002 budget information that Atlantic used to prepare its three months' forecast was way off.

There is reason to believe that Atlantic's financial situation continued to improve in 2003, despite the Company's claimed *pro forma* adjustments that pick up only increased costs. For example, PEPCO's Form 10-K for the year ending December 31, 2003[9] shows increased electric utility revenues of $144.7 million (page 106) and states, with respect to Atlantic that, "other operation and maintenance expenses decreased by $32.0 million to $211.6 million for 2003, from $243.6 million for 2002." (p. 107).

Thus, the Ratepayer Advocate recommends that Your Honor and the Board base its decision in this matter on 2002 test year actual data plus the Ratepayer Advocate accepted proposed capital additions to rate base through June 2003 and reject the Company's unsubstantiated post test year adjustments. Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board adopt the $614,769,000 rate base proposed by the Ratepayer Advocate and the associated $6.0 million decrease in the Company's revenue requirement. *RA-55*, Sch. 1.

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[9] Although the Company's 10-K filing was not entered into evidence in this proceeding, the document is available on the Company's website and the SEC website. The Ratepayer Advocate respectfully requests that Your Honor and the Board take judicial notice of this document.

POINT III

REGULATORY ASSET RECOVERY CHARGE ("RARC")

YOUR HONOR AND THE BOARD SHOULD EXCLUDE RECOVERY FOR THE CUMBERLAND CERTIFICATE OF NEED AND THE NUCLEAR RELATED COSTS FROM THE COMPANY'S PROPOSED RARC

A. Overview

EDECA defines a regulatory asset as "an asset recorded on the books of an electric public utility or gas public utility pursuant to the Statement of Financial Accounting Standards, No.71, entitled 'Accounting for the Effects of Certain Types of Regulation,' or any successor standard and as deemed recoverable by the Board." *N.J.S.A.* 48:3-51. In its initial filing the Company stated that its RARC was designed to recover Board approved regulatory assets which are not directly related to the current provision of electric power supply. Company witness Joseph F. Janocha listed the following regulatory assets as currently being recovered through the RARC:

a. Other Post Employment Benefit Costs associated with the implementation of FAS-106,

b. Costs associated with asbestos removal,

c. Costs associated with payments to a fund to pay for the decommissioning and decontamination of Department of Energy ("DOE") uranium-enrichment facilities, and

d. Costs associated with the cancellation of three separate ventures for the purpose of developing sources of uranium.

P-14, p. 7.

Mr. Janocha identified the RARC as a "uniform per kilowatt-hour charge that has been included in the Company's tariff since August 1, 1999 . . . designed to recover the regulatory assets that were included in rates as of that date." *Id.*

The Company initially proposed removing from the RARC the fully amortized costs of the three ventures for the purpose of developing sources of uranium and adding to the RARC recovery for:

a. Generation related losses on reacquired debt ($8.6 million),

b. Costs associated with Design Baseline Documentation and a Hydrogen Water Study related to the nuclear generation assets previously owned by the Company ($3.3 million),

c. Costs associated with the Cumberland Certificate of Need proceeding ($5.1 million), and

d. Costs associated with a 1993 Board mandated Management Audit of the Company ($550,000).

The Company proposed that these costs be recovered through the RARC over four years with a return on the unamortized balance. At the proposed interest rate of 3.06%, the proposed total annual revenue requirement would be $7.944 million. *P-14,* Sch. JFJ-3.

In supplemental testimony filed on April 16, 2004, the Company modified its proposed RARC to eliminate recovery for the DOE Enrichment Facilities Clean Up. *P-15*, p. 5. When responding to discovery, Atlantic determined that the Company no longer held any future funding commitment for these nuclear facilities. This adjustment reduced the proposed RARC total annual revenue requirement to $7.180 million. Subsequently, in supplemental testimony filed on October 28, 2003, Mr Janocha included recovery of costs associated with a 2000 BPU audit of $193,231. *P-16,* p.1 This proposed addition increased the Company's estimated annual revenue requirement for the RARC to $7.235 million.

Preliminarily, although these charges have been characterized by the Company as "Board approved," it is not clear from the Company's filing that the Company ever received Board authorization to recover Asbestos Removal Costs through the RARC. *P-14*, p. 7. These costs were incurred for an asbestos removal program initiated in 1986 for B.L. England and Deepwater. *Id*., Auditor's report, V-23. Originally, the Company capitalized these costs and included them in its 1990 Base Rate Case. Subsequently, pursuant to a 1993 FERC audit, Atlantic removed the asbestos removal costs from plant accounts and treated the insulation replacement as an expense. At that time, the Company established a regulatory asset for the removal and re-insulation costs. When asked to provide the Board Order in which the amounts currently being recovered through the RARC were approved, the Company referenced its response to S-CREV-37. *P-17*, Exhibit JFJ-7. In attachment 1 to BPU Staff Data Request S-CREV-37, the Company advised, in the column titled "BPU Approved," that "Recovery as regulatory asset based on 1993 FERC audit results." *Id.*

In a Board audit dated December 30, 1997, the auditors noted that "[t]he BPU has not yet provided specific approval of this regulatory asset." *Id.* Auditor's Report, p. V-24. The auditors recommendation stated:

> 1. ACE currently plans to include asbestos removal costs in the regulatory assets recovery charge (RARC). ACE should determine whether the current balance of the asbestos removal regulatory asset properly reflects the collection of the asbestos removal costs embedded in rates approved in the 1991 base rate case. *Id.* Auditor's Report, p. V-27.

Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board direct the Company to provide a complete accounting of the Asbestos Removal Costs currently being recovered from customers through the RARC including the total amount of asbestos removal costs allocated to Atlantic, the amount collected through rates, and the accounting which removed these costs from base rates and established the RARC recovery.

B. Cumberland Certificate of Need

Between 1989 and 1992, the Company considered installing generating units at Cumberland. In 1992, the Company determined that the additional capacity was not needed. The Company spent approximately $5.1 million on this determination. *P-14*, p.10. The Company admits that "the Cumberland facility was not constructed" and therefore "the costs were deferred in lieu of being capitalized and recovered through base rates." *P-17*, JFJ-7, RAR-RR-61. The Company claims that the "most appropriate alternative mechanism to recover these deferred costs is through an amortization mechanism to be included in the RARC." *Id.*

In testimony filed on January 5, 2004, Ratepayer Advocate witness Michael Dirmeier recommended exclusion of costs relating to the Cumberland Certificate of Need. *RA-50,* p. 48. Mr. Dirmeier reasoned that as the Cumberland Project was never constructed these costs represent costs that are not used and useful in the provision of electric service. Mr. Dirmeier explained that the Company had provided no justification for the inclusion of the costs for assets that were never used in the provision of electric service. Moreover, Mr. Dirmeier noted that as the Company had written off these costs in September 1999, allowance of these costs in rates would be a financial gain to the Company, since it will be recovering an expense that it does not have in its public financial reports. Mr. Dirmeier's recommendation regarding the Cumberland Certificate of Need reduced the Company's proposed revenue requirement by $1.441 million.

C. Design Baseline Documentation and Hydrogen Water Study Related to the Nuclear Generation Assets

The Company has also proposed full recovery with interest for the Hydrogen Water Chemistry Project ($590,409) and the Nuclear Plant Design Baseline Documentation. The Peach Bottom Hydrogen Water Chemistry system was placed in service in November 1991. *P-13,* Audit, p. v-26. However, in December 1991, operations ceased because the process created excessive radiation. The project was reassessed and canceled in 1992. In 1993, FERC approved the amortization of the project investment over the life of the Peach Bottom units. *P-17*, JFJ-7, RAR-RR-93.

The Company has not explained why New Jersey ratepayers will be charged with the payment of these costs that have not benefitted ratepayers and have not contributed to the provision of safe electric service in this state. The Hydrogen Water system was "in service" for maybe a month and during that time, apparently, created excessive radiation. Mr. Janocha claims that the Board must look beyond the "used and useful" standard and determine recovery based on the "reasonableness and prudency of the decision making involved." *P-17*, p. 16. And yet, beyond the Company's self serving statements that (1) the "co-owners agreed" and (2) that the project was "reasonable and rational," the Company has provided no support upon which the Board could base a finding of reasonableness and prudence. *Id*., p.17.

The Company is also proposing complete recovery with interest of the Design Baseline Documentation ("DBD") of the nuclear units ($4.0 million). Mr. Janocha supports the Company's claim for recovery on the basis that (1) the DBD was done "in response to requirements of the United States Nuclear Regulatory Commission ("NRC")" and (2) PSE&G received recovery of these amounts in their 1991 base rate case. *Id*. p. 14. Mr. Janocha does not reveal why the NRC determined that this documentation was necessary nor does he explain why New Jersey ratepayers are responsible for this cost. Mr. Janocha also fails to explain why recovery granted through the give and take of the settlement process in the PSE&G base rate case should be binding precedent in this proceeding. Moreover, the Company offers no justification for recovery of these amounts with interest over four years beyond the fact that this is "a time period similar to the one the Company recommended for amortization of the

Company's deferred balance." *P-14*, p. 12.

Based on the foregoing, the Ratepayer Advocate respectfully requests that Your Honor and the Board exclude the Company's nuclear related costs from the Company's RARC. Excluding the Design Baseline Documentation reduces the Company's revenue requirement by $1,047,000 and excluding the Hydrogen Water Project cost reduces the revenue requirement by $168,000.

POINT IV

DEPRECIATION

YOUR HONOR AND THE BOARD SHOULD REJECT ATLANTIC'S UNREASONABLE DEPRECIATION EXPENSE AMOUNT AND ADOPT THE RATEPAYER ADVOCATE'S RECOMMENDED AMOUNT, WHICH REFLECTS ADJUSTMENTS TO THE COMPANY'S 20-YEAR OLD DEPRECIATION RATES AND THE USE OF THE NET SALVAGE ALLOWANCE APPROACH.

Depreciation expense is included in Atlantic's revenue requirement and is passed on to ratepayers on virtually a dollar-for-dollar basis. Annual depreciation expense is determined by applying depreciation rates to plant investment. Depreciation rates are determined in depreciation studies. Generally, there are two components associated with depreciation. One is to recover invested capital, that is, money that has already been spent. Another component is the treatment of the cost of removing an asset at the end of its useful life.

Ratepayer Advocate witness Mr. Michael J. Majoros, Jr. found the Company's existing depreciation rates to be "too dated to be relied upon." *RA-60*, p. 2, ln. 17. Atlantic's existing depreciation rates are over 20-years old. The Company's depreciation rates were last set in 1983.[10] Mr. Majoros testified that the Company's depreciation rates needed to be updated using current plant balances and more recent plant activity data. *Id.*, p. 2, ln. 17-19.

After careful study and analysis, Mr. Majoros found that Atlantic overstated its deprecation expense proposal. Mr. Majoros recommended that the Company's total proposed depreciation claim should be reduced by \$13.0 million, from \$49.4 million to \$36.4 million. *RA-62*, pp. 4-5, Table 1. Mr. Majoros recommended decreases in the Company's composite depreciation rates for the Transmission and Distribution functions, an increase in the composite

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[10] *See RA-60*, Exh. MJM-1.

rate for General Plant, and an adjustment for net salvage. *Id*. For Transmission Plant, Mr. Majoros recommended that the composite depreciation rate be reduced from 2.85% to 2.36%, which reduces the associated depreciation expense from $10.4 million to $8.6 million. *Id.*, Table 1. For Distribution Plant, Mr. Majoros recommended that the composite depreciation rate be reduced from 3.82% to 2.13%, which reduces the associated depreciation expense from $34.8 million to $19.4 million. *Id*. For General Plant, Mr. Majoros recommended that the composite depreciation rate be increased from 3.57% to 4.60%, which increases the associated depreciation expense from $4.3 million to $5.5 million. *Id*. Finally, Mr. Majoros recommended a net salvage allowance of $2.9 million to recover a normalized level of net salvage expense. *Id*. Mr. Majoros' recommendations are summarized in Table 1, found in his supplemental surrebuttal testimony. *RA-62*, p. 4, Table 1.

As set forth in his prefiled testimony, Mr. Majoros followed a disciplined, reasoned approach in his analysis of Atlantic's depreciation practices and in the development of his recommendations. Mr. Majoros conducted two types of statistical analyses of plant balances provided by the Company: the Simulated Plant Record ("SPR") method and Geometric Mean Turnover ("GMT") method. *RA-60*, p. 13. The type and nature of Atlantic's data provided to Mr. Majoros dictated the use of these approaches versus other types of analysis. In his analysis Mr. Majoros first used the SPR method, then used the GMT method "to test and corroborate where possible the results of ... [his] SPR studies." *Id.*, p. 14, ln. 12-13. Mr. Majoros also examined the Company's reported actual net salvage expenditures. *Id*., p. 33. Additionally, Mr. Majoros considered the Company's life extension and maintenance plans in his analysis. *Id.*, pp. 14-16, Exh. MJM-3.

For consistency, Mr. Majoros maintained the same technique for each function that underlies the Company's current depreciation rates. *RA-61*, p. 4. For example, Mr. Majoros continued the use of the remaining life technique for distribution and transmission assets, and continued the use of the whole life technique for general plant assets. *See RA-60*, pp. 8, 18, 22; *RA-61*, p. 5; and *RA-62*, p. 3. In sum, as set forth below and in his testimony, Mr. Majoros' disciplined analytical approach resulted in reasonable depreciation rate and expense recommendations, supported by ample evidence in the record and consistent with recent Board rulings.

A. Transmission Plant

As proposed, Atlantic's Transmission depreciation expense is overstated. Mr. Majoros found that Mr. Robinson significantly understated the useful life of assets in Account 354-Transmission Towers and Fixtures. *RA-62*, pp. 2-3. Mr. Robinson suggested a 50-year life for assets in that account, whereas Mr. Majoros' studies support a 74-year life. *Id*. Mr. Majoros' recommendation is supported by industry data and the Company's own life extension practices. Mr. Majoros testified that the maximum life for such assets in the industry is 86 years, and his life estimate of 74 years is within the industry range. *Id*. Furthermore, as Mr. Majoros testified, in response to a discovery request, the Company provided documentation of a Company initiative to extend the lives of transmission towers and foundations. *Id*., p. 3.

Since the current depreciation rates for Transmission Plant were based on remaining life rates, Mr. Majoros calculated remaining life rates as part of his analyses. *RA-62*, p. 3. Based on the results of his studies, Mr. Majoros recommended a 2.35% composite depreciation rate for the Company's Transmission assets, resulting in a depreciation expense accrual of $8.6 million. *RA-60*, p. 4, Table 1. On the other hand, Atlantic's claimed Transmission depreciation rate and accrual (2.85% and $10.4 million, respectively) reflect Mr. Robinson's unreasonably short lives for assets in Account 354. *Id*. Mr. Majoros' recommended Transmission depreciation accrual is $1.8 million less than that proposed by the Company. *Id*. As set forth above and in Mr. Majoros' filed testimony, Mr. Majoros' recommended Transmission depreciation rate and expense accrual are reasonable, supported by ample evidence in the record, and should be adopted by Your Honor and the Board.

B. Distribution Plant

As noted above and in Mr. Majoros' testimony, Atlantic's existing depreciation rates for Distribution Plant are 20 years old. As part of his depreciation study, Mr. Majoros examined documents outlining the Company practices which could affect service lives. *RA-60*, pp. 14-16. Mr. Majoros found that the Company "has substantial maintenance programs in place that will help to lengthen plant lives." *Id*., p. 15, ln. 23 - p. 16, ln. 1; *RA-62*, pp. 2-3, Exh. MJM-10. Furthermore, Mr. Majoros found evidence that the results of these programs were apparent in statistical analyses. *Id*., p. 16, ln. 1-2. Mr. Majoros applied SPR and GMT analyses to the plant account data. Consistent with existing rates, Mr. Majoros used the remaining life parameters with no net salvage. *Id*., p. 18. Based on his life analyses, Mr. Majoros proposed changes to the depreciation rates for Distribution Plant accounts 361 through 373. *See RA-60*, p. 18, Table 7. Mr. Majoros' analyses support his recommendation that the composite depreciation rate for Distribution Plant should be reduced from 3.82% to 2.13%. *RA-62*, p. 4. This reduction would decrease the associated depreciation expense from $34.8 million to $19.4 million. *Id*.

C. General Plant

Mr. Majoros also examined General Plant data suppled by Atlantic, and applied both SPR and GMT analyses to that data. *RA-60*, pp. 22-25. Mr. Majoros examined and analyzed General Plant Accounts 390 through 398. *RA-60*, p. 22, Table 8. Much like his analysis of Transmission Plant and Distribution Plant, Mr. Majoros fitted Iowa Curves to the individual General Plant account data as part of his SPR and GMT analyses to estimate asset lives. *See Id*., pp. 22-25. Based on his analyses, Mr. Majoros recommended that the composite depreciation rate for General Plant should be increased from 3.57% to 4.60%. *RA-62*, p. 4. This adjustment would increase the associated depreciation expense from $4.3 million to $5.5 million. *Id*.

D. Net Salvage

Net salvage is the difference between gross salvage and the cost of removal of the plant. Gross salvage is the amount recorded due to the sale, reimbursement, or reuse of retired property. The cost of removal is connected to disposing of retired depreciable plant. Net salvage is positive when gross salvage exceeds cost of removal. Net salvage is negative when cost of removal exceeds gross salvage. A positive net salvage ratio reduces the depreciation rate and depreciation expense, while a negative net salvage ratio increases the depreciation rate and depreciation expense. *RA-60*, pp. 25-26.

Mr. Majoros found that Atlantic's existing depreciation rates do not include a provision for net salvage. *Id*., pp. 26-27. Moreover, Atlantic has not collected cost of removal expenses from its ratepayers for the past 20 years, since its depreciation rates were last set in 1983. *Id*., p. 27. Mr. Majoros recommended that the Board adopt a normalized net salvage allowance for

Atlantic equal to the average of the Company's actual annual net salvage activity for the most recent five-year period. *Id*., p. 33. All else equal, Mr. Majoros' net salvage recommendation increases Atlantic's depreciation expense. In this regard, it should be recognized and remembered that status quo on net salvage for Atlantic would result in no net salvage allowance at all. Therefore, the reasonableness of Mr. Majoros' recommendation is beyond challenge. As set forth below, Mr. Majoros' recommended net salvage allowance approach is consistent with the Board's rulings in two recent electric utility base rate cases, and recognizes current accounting thought on accounting for net salvage.

In two recent electric utility base rate cases, the Board adopted the net salvage allowance concept recommended by Mr. Majoros. In the most recent JCP&L base rate case, the Board rejected recovery of net salvage cost through depreciation rates and provided for their recovery by adopting a net salvage allowance equal to the Company's test year removal expense.[11] Similarly, in the most recent Rockland Electric Company base rate case, the Board rejected recovery of net salvage expense through depreciation rates and adopted a net salvage allowance based on an amount equal to a ten-year average of Rockland's net salvage expense.[12]

Furthermore, Mr. Majoros' net salvage allowance approach reflects current thought about net salvage expense accounting. Mr. Majoros testified that the Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standards ("SFAS") Number 143 ("SFAS 143"or "FAS 143") constitutes GAAP ("Generally Accepted Accounting Practice") at the present time, with respect to the accounting requirements relating to net salvage. *RA-60*, p. 27. A subsequent Order of the FERC ("FERC Order 631"), requires that any recovery of net salvage

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[11] *I/M/O JCP&L*, BPU Dkt. Nos. ER0208056, ER0208057, EO02070417, and ER0203013 (Final Order, 5/17/04), p. 54.

[12] *I/M/O Rockland Electric Company*, BPU Dkt. Nos. ER02080614 and ER02100724 (Final Decision and Order, 4/20/04), pp. 67-68. *See also RA-60*, pp. 29-33.

be specifically identifiable within depreciation, which Mr. Majoros called the "separation principle." *Id*., pp. 27-28. FERC Order 631 requires that collections for net salvage be included in specifically-identifiable allowances and accounted for separately in depreciation expense and the accumulated depreciation account. *Id.*, p. 29. Mr. Majoros' net salvage allowance approach separately identifies net salvage expense and provides for recovery of that expense as a line item, rather than as an expense incorporated into depreciation rates. Mr. Majoros testified that his recommended net salvage allowance approach "is consistent with the principles and concepts of both SFAS 143 and Order No. 631." *Id*., ln. 13-15.

Mr. Majoros calculated his recommended net salvage allowance. Based on an average of the Company's actual annual net salvage experience, using FERC Form 1 amounts, his recommended net salvage allowance amounted to $2.9 million. *Id.*, p. 33. Mr. Majoros' recommended net salvage allowance is a conservative figure, since it includes all plant, not only jurisdictional distribution and general plant. *Id*.

For the reasons set forth above, Your Honor and the Board should adopt the ratemaking treatment of net salvage recommended by Ratepayer Advocate witness Michael J. Majoros for the Company's annual expense levels.

E. Conclusion

As set forth above and in filed testimony, Mr. Majoros' depreciation rates and net salvage allowance recommendations are reasonable and supported by ample evidence in the record. The Ratepayer Advocate respectfully urges Your Honor and the Board to adopt Mr. Majoros' depreciation recommendations.

POINT V

COST OF SERVICE/RATE DESIGN

YOUR HONOR AND THE BOARD SHOULD ADOPT THE RATEPAYER ADVOCATE'S REVENUE DISTRIBUTION PROPOSALS.

A. Your Honor and the Board Should Reject the Company's Revenue Allocation Proposal and Allocate any Rate Decrease or Rate Increase Using the Company's Flawed Cost of Service Study Only as a General Guide.

The Ratepayer Advocate's proposed methodology for allocating any base rate decrease or rate increase that results from this proceeding is explained in the testimony of Ratepayer Advocate witness John K. Stutz, Ph.D. As Dr. Stutz explained, Atlantic, through the testimony of Joseph F. Janocha, proposed a methodology which would allocate none of the Company's proposed $36.657 million rate increase to five of its ten customer classes, while allocating all of the increase to the remaining five classes. *RA-10,* pp. 7-8. This methodology should be rejected. It relies heavily on the Company's flawed cost of service study ("COSS"), and it would place disproportionate impacts on some customer classes including residential, smaller commercial, and street lighting customers. *RA-10,* pp. 18-19; Sch. JS-3. Instead of the Company's approach Your Honor and the Board should adopt the following approach recommended by Dr. Stutz, using the Company's cost of service study only as a general guide:

> Any increase in distribution rates should be allocated so that rate classes shown by Atlantic's COSS to be contributing more than the Company's system average rate of return would receive 50% of the overall percentage increase, with the remaining classes receiving an above-average increase.
>
> A rate decrease should be allocated so that rate classes shown by Atlantic s COSS to be contributing more than the Company's system average rate of return would receive 150% of the average percentage decrease, with the remaining classes receiving a below-average decrease.

This methodology would result in all classes sharing in either a rate increase or a rate decrease, while giving recognition to those classes which Atlantic's cost of service study shows as producing above-average rates of return. *RA-10*, p. 20.

1. Flaws in Atlantic's Cost Allocation Methodology

The methodology used by Atlantic as described by the Company to allocate its proposed rate increase involved three steps:

> First, rate class specific allocations of distribution revenues, net operating income and rate base for 2001 were taken from a COSS performed by Company witness Carl D'Adamo.
>
> Second, the allocations reflected in the COSS for 2001, along with the resulting relative contributions of each class to the Company's rate of return, were assumed to be unchanged for the test year, calendar year 2002.
>
> Third, the Company's proposed rate increase was divided among the five classes shown in the Company's COSS as contributing less than the Company's overall rate of return with the remaining classes receiving no increase.

RA-20, p.18.

As Dr. Stutz explained in his prefiled direct testimony, each step of this procedure raises serious concerns.

a. COSS is of Poor Quality

The first step of the Company's methodology is flawed, because the Company's COSS is of poor quality. As detailed in Dr. Stutz's testimony, the Company has failed to document that the 2001 COSS was properly performed.

From the outset, the Company's presentation of its COSS created questions about its reliability. The COSS was prepared by Company witness Carl D'Adamo, whose initial prefiled testimony, dated February 3, 2003, included two schedules purporting to summarize the results of his COSS. *P-10*, p. 2; *RA-6; RA-8.* However, no COSS was submitted with the initial prefiled testimony. T164:L8-11. During his cross-examination, Mr. D'Adamo explained the reason for this omission. At the time the Company submitted his original prefiled testimony, the cost of service study was incomplete. T161:L17-20. However, the prefiled testimony contained no indication that the study was incomplete. T252:L3, T252:L8.

The Company's COSS was provided over two months later, on April 16, 2003, when the COSS was circulated along with revised versions of the two schedules summarizing the results. *P-11*. Although the revised schedules reflected substantial differences from the original versions, there was no supplementary testimony explaining the reasons for the changes. *Id; RA-10,* p. 14-15. When Mr. D'Adamo was asked about these changes in a Ratepayer Advocate discovery request, he acknowledged that he had originally "included plant investment, expenses and revenues that were inappropriate for inclusion in a distribution cost of service study." *RA-10,* p. 15. The same discovery response went on to explain that the inappropriately included revenues amounted to approximately $45.3 million. *Id.*

Furthermore, the Company failed to provide the information needed by Dr. Stutz for a complete review of Mr. D'Adamo's study. As Dr. Stutz explained, the appropriate starting point for evaluating the COSS presented in this proceeding is the 1996 COSS adopted by the Board in Atlantic's restructuring proceeding. This approach is consistent with the criteria of rate stability and simplicity. *RA-10*, p. 16. Further, this proceeding is Atlantic's first base rate proceeding following its electric restructuring proceeding, making it particularly appropriate to continue the COSS methods used in unbundling the Company's rates. *Id.* Dr. Stutz attempted to review the Company's current COSS for consistency with the study adopted by the Board in the unbundling proceeding. However, despite two separate discovery questions requesting that the Company identify and explain each change from the 1996 study, the Company never produced such a list.

RA-10, p.16. *RA-11,* p. 4-5. Without this information, Dr. Stutz was unable to review the consistency of the new study with the one adopted by the Board in Atlantic's restructuring proceeding.

The above casts substantial doubts on the credibility of the Company's study. The Company initially filed purported "summaries" of a COSS, without disclosing that these summaries were based on an incomplete study. Then when the Company finally submitted its competed study, it failed to explain the discrepancies between the competed study and the summaries submitted two months earlier. The Company acknowledged the errors reflected in its original prefiled testimony only after the Ratepayer Advocate propounded discovery requesting an explanation of the discrepancies between the original and revised summaries. These developments made it especially important that there be a thorough review of the Company's COSS. Nevertheless, despite two requests, the Company did not provide the information required for such a review. The Company's evasiveness in the initial submission of the COSS, the substantial errors reflected in Mr. D'Adamo's original prefiled testimony, and the Company's refusal to fully explain the changes from the previous COSS, seriously undermine the credibility of the study.

b. Mismatch Between Test Year and COSS.

The Company's allocation methodology is also flawed because it uses a COSS based on 2001 data to allocate rate base and net income for 2002. As Dr. Stutz explained, there have been substantial changes between 2001 and 2002 in the data that goes into a COSS, including a 12.4% increase in Distribution Rate Base, a 12.5% decrease in Distribution Operation and Maintenance Expense, and major changes in the numbers of customers in various rate classes. *RA-10,* p. 18, 19-20; Sch. JS-6. In light of these changes, there is no basis for assuming that the allocations of rate base and net income among customer classes for 2001 can be extrapolated to 2002. *Id.* As Dr. Stutz testified, Mr. Janocha's reliance on the 2001 study is "particularly problematic" given the substantial changes between 2001 and 2002. *RA-10,* p. 19.

c. Inequitable Allocation of Increases

The third step of the Company's allocation procedure is flawed because it is based on a narrow definition of "equity" that does not give adequate consideration to the public acceptability of the resulting rate structure. As shown in Mr. Janocha's Rebuttal Schedule JFJ-1, the Company is proposing to allocate all of its proposed $30.6 million rate increase to only five of ten customer classes. *P-17,* Sch. JFJ-1. Moreover, since Atlantic's initial filing, the Company has proposed to allocate its proposed rate increases to successively fewer customer classes. The Company's initial filing proposed an across-the-board increase, sharing a proposed $63.5 million increase among all customer classes. The Company's April, 2003 revision proposed to allocate the same proposed increase to seven customer classes, with three classes receiving no increase. Finally, as noted, Mr. Janocha's rebuttal testimony allocated a proposed $30.6 million increase to only five customer classes. T265:L13; T267:L3; *RA-9.*

The Company's latest proposal places a disproportionate impact on the limited number of rate classes receiving a rate increase. As shown on Mr. Janocha's Rebuttal Schedule JFJ-1a, based on a proposed system average distribution rate increase of 11.84%, the Company's proposal would result in increases of 15.75% to residential customers, 16.29% to smaller commercial customers, and 21.84% to the two street lighting classes. *P-17*, Sch. JFJ-1a. As Dr. Stutz noted in his testimony, it is unlikely that Atlantic 's proposed allocation would meet the test of public acceptability. *RA-10,* p. 12. Dr. Stutz's testimony is confirmed by comments submitted to the Board by Atlantic County and several Atlantic County communities expressing their concerns about Atlantic 's proposed increases in street lighting rates.[13]

2. Ratepayer Advocate's Proposed Allocation Methodology

Although the Company's COSS is flawed, the Ratepayer Advocate is not recommending that it be ignored completely in allocating the rate increase or rate decrease resulting from this proceeding. Instead, the Ratepayer Advocate is recommending that the Company's COSS be used as a general guide to determine which customer classes are contributing more than the Company's system average rate of return. In the event of a rate increase, those classes would receive 50% of the system average rate increase. In the event of a rate decrease, those classes would receive 150% of the system average decrease. *RA-10*, p. 20. This approach is more equitable than the Company's proposal, because it would allocate a portion of any rate increase or decrease to all customer classes, while still giving recognition to those classes shown by the Company's COSS to be contributing more than their proportionate share of the Company's system average rate of return. *RA-10,* p. 21.

For the above reasons Your Honor and the Board should use the Ratepayer Advocate's methodology for allocating any rate increase or rate decrease among customer classes.

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[13] The Ratepayer Advocate has received copies of correspondence and/or resolutions from Atlantic County and several Atlantic County communities including Abescon, Atlantic City, Borough of Buena, Buena Vista Township, Hamilton Township, Mullica Township, the Borough of Folsom, Egg Harbor City, and Pleasantville,

B. If the Board Orders a Change in Atlantic's Cost of Service Study Methodology, It Should Require the Company to Allocate a Portion of Distribution Costs Based on Year-Round Electricity Usage.

Based on considerations of rate stability, the Ratepayer Advocate is not recommending that the Board implement a new cost of service study methodology for Atlantic in its first base rate case following the Company's restructuring proceeding. *RA-10*, p. 16. However, two other parties, the NJLEUC and the Board Staff, have suggested changes in the Company's methodology. If the Board should decide to order a change, it should adopt a methodology which allocates a portion of distribution costs based on year-round electricity usage, as suggested by Staff, and reject NJLEUC's suggestion that a portion of distribution-related costs be based on the number of customers in each class.

Atlantic currently allocates the costs of its distribution system based on Class Non-Coincident Peak Demands. *P-10*, p. 5-6; *RA-11*, p. 11. This "demand-only" methodology is inconsistent with the Board's decision in the 1991 Jersey Central Power and Light Company base rate case. *I/M/O 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 (June 15, 1993) (referred to hereinafter as the "*1993 JCP&L Base Rate Order*"). In the JCP&L proceeding, the United States Department of Defense and Federal Executive Agencies had proposed to allocate transmission, subtransmission and distribution costs based solely on non-coincident peak demands, while the Division of Rate Counsel proposed an "average and excess" method which considered both peak demand and annual energy usage. *JCP&L 1993 Base Rate Order*, p. 16. Noting that "[e]xclusive demand approaches to the allocation of T&D costs" had been rejected in a previous rate proceeding, the Board adopted the methodology advocated by Rate Counsel. *Id.*

The methodology adopted in the *JCP&L 1993 Base Rate Order* was recently re-affirmed in the Board's May 17, 2004 Final Order in JCP&L's 2002 base rate proceeding. As stated in that Final Order, "[t]he Board reiterates its full support of the average and Excess Cost of Service Study Methodology as prescribed in JCP&L's 1992 and 1993 Orders ...." *I/M/O the Verified Petition of Jersey Central Power and Light Company for Review and Approval of an Increase in and Adjustments to its Unbundled Rates and Charges for Electric Service and for Approval of Other Proposed Tariff Revisions in Connection Therewith,* BPU Docket Nos. ER02080506 *et al.,* Final Order at 74 (May 17, 2004). Further, since JCP&L's 2002 base rate proceeding involved rates for unbundled electric distribution rates, the Board's statement affirms the continuing applicability of this methodology in a post-EDECA environment.

In accordance with the Board's April 30, 2004 Order on Motion for Interlocutory Review in this matter, the record of this proceeding includes a modified version of Atlantic's COSS, prepared by Atlantic at Staff's request, which allocates distribution system related costs based on a combination of demand and energy-based allocation factors. *S-2. See Order on Interlocutory Review* at 12. For the reasons explained in the Board's *JCP&L 1993 Base Rate Order,* Your Honor and the Board should follow this approach if a modification to Atlantic's cost of service study methodology is determined to be appropriate.

The Ratepayer Advocate notes that, if Your Honor and the Board decide to follow this approach, the methodology recommended by Dr. Stutz could be used to allocate the rate increase or decrease resulting from this proceeding. In other words, those rate classes shown by the cost of service study to be contributing more than the system average rate of return should be allocated 50% of the overall increase, or 150% of the overall decrease, with the remaining increase or decrease allocated to the remaining customer classes. *RA-10,* p. 20.

NJLEUC witness Jeffrey Pollock presented testimony proposing that Atlantic's COSS be modified to allocate a portion of the costs of the Company's distribution system based on the number of customers in each class. This proposal was based on the theory that the distribution system serves two functions, "attach[ing] customers to the system", and "meeting the maximum rate of usage (demand) that customers impose." *NJLEUC-9*, p. 6. Ratepayer Advocate witness Dr. Stutz explained the fallacy of this approach. Mr. Pollock's approach assumes that the cost of extending the Company's distribution system to cover its service area is related to the number of customers served. However, population densities differ in urban, suburban, and rural areas, a fact which makes the number of customers a poor proxy for the costs of extending service to cover the service area. *RA-11,* p. 12. Further, Mr. Pollock's proposal is contrary to the *JCP&L 1993 Base Rate Order* which, as noted, states that distribution system related costs should be allocated based on a combination of demand-based and energy-based allocators.

For the above reasons, if Your Honor and the Board should decide to modify Atlantic's cost of service study methodology, the Company should be required to allocate its distribution system related costs based on a combination of demand and year-round energy usage.

POINT VI.

SERVICE RELIABILITY

THE RATEPAYER ADVOCATE RESPECTFULLY REQUESTS THAT YOUR HONOR AND THE BOARD IMPOSE PENALTIES ON THE COMPANY FOR FAILURE TO ACHIEVE MINIMUM PERFORMANCE LEVELS ESTABLISHED BY THE BOARD

A. Measurement and Analysis of Reliability Performance

On November 28, 2000 the Board adopted Interim Electric Distribution Service Reliability and Quality Standards which require the annual calculation and reporting of the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI).[14] The Board established benchmark performance levels equal to the 10 year historical average for SAIFI and CAIDI and minimum reliability levels equal to the benchmark plus two standard deviations. *N.J.A.C.* 14:5-7.2. The Board directed that each utility "shall take reasonable measures to perform better than the minimum reliability levels." *N.J.A.C.* 14:5-7.3.

Ratepayer Advocate witness Peter Lanzalotta testified that since 1997 the Company's reliability performance, as measured by SAIFI and CAIDI, has shown a gradual decline. In 1999 and in 2002, the Company failed to meet the BPU Bench Mark reliability standard for SAIFI and in four of the past six years failed to meet the BPU Bench Mark reliability standard

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[14] SAIFI "represents the average frequency of sustained interruptions per customer" while CAIDI "represents the average time in minutes required to restore service to those customers that experienced a sustained interruption." *N.J.A.C.* 14:5-7.2

for CAIDI.[15] Without stricter reliability standards, Mr. Lanzalotta testified, he would expect that reliability would continue to deteriorate. *RA-4*, p. 9. Indeed, the Company's average levels of CAIDI and SAIFI could increase substantially[16] without exceeding the current minimum reliability levels set by the Board. For example, the Company's 10-year SAIFI Bench Mark is 0.779 while the minimum reliability level is 1.132. Similarly, the Company's 10-year CAIDI Bench Mark is 84.802 while the minimum reliability level is 131.58. Thus, the current minimum reliability levels have room to accommodate deteriorating service built into them.

The Company has taken the position that the dramatic decline in the Company's reliability performance for 2002, denoted by increases in SAIFI and CAIDI, is reflective of the Company's implementation of its Outage Management System ("OMS"). The Company has asserted that, because of the implementation of OMS, its performance can no longer be accurately compared to historic levels of performance. The Company claims that the implementation of its Outage Management System ("OMS") "makes it impossible to compare today's statistics to ones of the previous years prior to implementation of the OMS" and that it is OMS that is "delaying the finalization of statewide standards." *P-4*. p.3 Thus, the Company is advocating that the Board put off setting any standards against which a utility's performance can be measured until 2006.

The Company, by providing what it characterizes as "blended information," is attempting to frustrate the Board's ability to hold the state's utilities to even the minimum reliability performance levels established by the Board's Interim Electric Distribution Service

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[15] The Company's 10 year SAIFI Bench Mark is 0.779 while the minimum reliability level is 1.132. Similarly, the Company's 10 year CAIDI Bench Mark is 84.802 while the minimum reliability level is 131.58.

[16] Increases in SAIFI and CAIDI denote decreases in reliability.

Reliability and Quality Standards. The Company completed implementation of OMS in New Jersey in December 2001 and began using the statistics at that point. T21:L13-16. In fact, some districts were using OMS as early as 2000 and were running both the pre-OMS legacy system and the OMS system parallel "for a long period of time." T23:L5-12. And yet, for some reason, the Company chose to discontinue running the parallel systems and, in June of 2002, the Company collected data only through its OMS. *Id*. So, according to the Company, as the 2002 data is actually a "blend" of the legacy system and the OMS data, "it is not appropriate to compare it to anything . . ." T28:L13-18. The Company claims to have been running parallel systems in 2002. And yet, rather than provide the Board with only OMS data for 2002, which presumably had been collected in the parallel systems, the Company chose to "blend" the pre-OMS numbers collected in January through May and the OMS numbers collected in June through December. If the OMS January through May numbers were flawed, then the Company should have continued the parallel running of the legacy system to provide the Board with a valid basis for comparison of 2002 results with previous years. Unfortunately, choosing instead to provide "blended" data, the Company has frustrated for at least another year the timely implementation of BPU reliability standards.

Further, as noted by Mr. Lanzalotta, while OMS implementation may have increased the Company's apparent number of reliability problems, part of the increase in reliability problems seems likely to be the result of a decline in actual reliability performance. For example, Mr. Lanzalotta notes the significant increase in distribution transformer failures in 2003 cannot be explained solely as the result of more accurate recording of transformer failures, especially as OMS data was being recorded in the summer of 2002 when the majority of transformer failures typically occur. As noted by Mr. Lanzalotta, the additional five months of OMS data in 2003 were the months of January through May, when ambient air temperatures and distribution transformer loadings are typically lower than in summer months. Thus, while the implementation of the OMS may have had some impact on the Company's recording of outage data, this should not be interpreted by Your Honor and the Board to mean that the Company's decline in reliability performance has been reversed.

The Company has also taken somewhat conflicting positions regarding the measurement of its performance against the performance of other utilities. On the one hand, the Company brags that based on a comparison of reliability performance with respect to other New Jersey utilities and within the industry, "the Company's customers enjoy better than average level of reliability." *P-2,* p. 13, Sch. JAE-9.1 and JAE-9.2. Then, in the next paragraph, the Company limits this comparison citing "inconsistencies; e.g., differences in utility service territories and work practices." *Id.* In fact, at the hearing the Company seemed to say that pretty much any comparison between the Company and other utilities was basically useless. First, the Company admitted that the surveys relied upon by the Company contained a combination of pre- and post OMS data. T31:L17-25. As Mr. Elliot informed us, data collected after the implementation of OMS is "not directly comparable" to data collected before the implementation of OMS. *P-4*, p. 6. Thus, comparing Atlantic 's pre-OMS data with other utility post OMS data is exactly what the Company said the Ratepayer Advocate should not do.

Furthermore, Atlantic is comparing its data to other utilities using a different set of definitions for outages that are included in the data collection, different service territories with different weather conditions, and different work practices. T33:L4-7. As explained by Mr. Elliot:

Just defining what an outage is sometimes can be different from one utility to

> another. Some record it after one minute being off, other ones record it after being five minutes off. So depending on what system you are using, even what an outage is could change from one to the other. This's why it is difficult. You can't compare the two, even though we would love to compare them. T42:L15-23

Thus, the Company's claim that compared to other utilities Atlantic's customers "enjoy better than average level of reliability" is basically meaningless.

In reviewing the Company's reliability data, Ratepayer Advocate witness Peter Lanzalotta identified several areas of concern and made recommendations based on these findings.

First, Mr. Lanzalotta noted that the number of equipment failures had increased from 335 events in 2001 to 1,837 events in 2002, an increase of more than 400%. *RA-4,* p. 14. Specifically Mr. Lanzalotta found that the number of outages and customer interruptions due to distribution transformer failure have been increasing since 1999, when a very hot summer resulted in large numbers of such failures on the Atlantic system. Based on this finding, Mr. Lanzalotta recommended that the Company implement a Transformer Load Monitoring (TLM) program. *Id*., p. 17. A TLM program is one in which a utility periodically determines the approximate peak load on each distribution transformer and develops a list of potential overloaded transformers. These transformers would then be inspected and units showing signs of overloading are replaced with a larger transformer or have load removed by transferring some of the customers to another transformer. Mr. Lanzalotta reasoned that in this way, overloaded transformers would be replaced or unloaded before they fail, which is typically during a heat wave, when they would otherwise fail in large numbers. Mr. Lanzalotta further recommended that the Company should shorten the time between inspections and/or maintenance of major system components. Mr. Lanzalotta recommended that the Company return to its former policy of a five year inspection and maintenance cycle. *Id*., p. 21.

Second, Mr. Lanzalotta noted that animal related outages are the leading driver of outage events. *Id*., p. 22. In 2002, there were more outage events caused by animals than were caused by any other single cause category, and the number of animal caused outage events in 2002 were higher than in any of the five proceeding years. Mr. Lanzalotta said that these types of outages could be reduced by the installation of wildlife protection devices which prevent animals from contacting the energized component and a grounded component at the same time. Mr. Lanzalotta, while recognizing that the Company's policy of installing wildlife protection on new installations and on equipment experiencing animal related fault was similar to other utilities in the region, recommended a more aggressive approach. Mr. Lanzalotta recommended that the Company adopt a program of installing wildlife protection on all relevant overhead distribution equipment within a given period of time, but no longer than 10 years.

Third, Mr. Lanzalotta found that the minutes of interruptions caused by tree related factors almost tripled in 2002 with 30,590,814 minutes of interruptions compared with 10,998,687 minutes in 2001. *Id*., p. 14. Mr. Lanzalotta reviewed the Company's tree trimming data and found a number of distribution feeders had not been trimmed for over ten years. Mr. Lanzalotta further found a correlation between frequency of trimming and performance. According to Mr. Lanzalotta, the Company concentrates its tree trimming efforts where vegetation management would alleviate potential problems for the greatest number of customers. This has the effect of putting off maintenance in other areas until reliability deteriorates. Mr. Lanzalotta posited that while this approach may tend to maximize the reliability impact of the available tree trimming budgets, it can result in a system-wide deterioration of reliability performance. Mr. Lanzalotta concluded that the disproportionate increases in the number of customer interruptions and of interruption minutes due to factors related to trees and in the percentage of customer interruptions and the percentage of interruption minutes due to factors related to trees gives cause for concern over the present and future reliability related impacts due to causes related to trees. Mr. Lanzalotta recommended that the Company increase vegetation inspections to once every two years, with trimming performed as needed in order to increase electric system reliability.

B. Penalties

Ratepayer Advocate witness John Stutz recommended the adoption of penalties for declines in Service Quality. Dr. Stutz suggested that the Board could establish penalties equal to .25 percent of Atlantic 's distribution revenues if SAIFI or CAIDI rises above the minimum reliability level. To discourage any deterioration in service quality, the penalties could phase in linearly, beginning at the benchmark performance level. Thus, for example, if in a particular year SAIFI falls half-way between the benchmark and the minimum reliability level, the associated penalty would be .125 percent of distribution revenues. This phase-in of penalties would encourage Atlantic to improve its performance. While the Ratepayer Advocate recognizes that the implementation of OMS has made the comparison of historical performance to current performance less precise, there is sufficient leeway in the Interim Standards to allow for the imposition of penalties if the Company fails to meet the minimum reliability level. Accordingly, the Ratepayer Advocate respectfully requests that Your Honor and the Board impose penalties on the Company for the failure to achieve the minimum performance levels set in the Board's Interim Reliability and Service Quality standards.

POINT VII.

SERVICE COMPANY AGREEMENT

YOUR HONOR AND THE BOARD SHOULD NOT APPROVE THE SERVICE COMPANY AGREEMENT IN ITS PRESENT FORM.

The Service Agreement between Atlantic and PHI Service Company ("PHISC" or the "Service Company") was filed with the Board on September 6, 2002 in Docket No. EM02090633. The Service Company, which is a mutual service company providing a variety of support services to its operating subsidiaries, had its Service Agreement approved on July 24, 2002 by the Securities and Exchange Commission as part of the merger Order approving the Conectiv/PEPCO merger. *P-27,* p. 2. The Commonwealth of Virginia granted its approval of the Service Agreement on June 28, 2002.

Following the merger, Conectiv's Service Company (Conectiv Resource Partners, Inc. or "CRP") was renamed PHI Service Company, and, according to the Company, is still in the process of being "transitioned over" to PHISC. Currently, the transition phase is approximately 75% complete. T808:L4-5. The transition should be complete by the beginning of 2005. T808:1-2.

Preliminarily, it should be noted that Atlantic has agreed in principle with two Ratepayer Advocate recommendations from our original examination of the Service Agreement. First, the Company has committed to a 10% allocation to the holding company. T817:l17-25. The Ratepayer Advocate applauds this commitment and recommends that it be added to the Service Agreement. Secondly, the Company has agreed to certain reporting and notification procedures recommended by this office. The Ratepayer Advocate urges Your Honor and the Board to include these in any subsequent Initial Decision and Board Order.

A. The Direct-billed Costs Should Represent the Majority of the Costs Allocated and the Indirect-billed Costs Should Represent the Minority of the Costs Allocated.

Charges to Atlantic from PHISC are a significant part of Atlantic's annual expenses. In fact, in 2002, CRP billed Atlantic $92.6 million. *RA-19,* p. 4. The Ratepayer Advocate believes that, as PHISC and Atlantic are both affiliates of Pepco Holdings, Inc., and, as all three companies share common corporate directors and officers, transactions between Atlantic and PHISC are not "arm's length." Thus, it is vitally important that New Jersey ratepayers are protected from abuses of self-dealing and unreasonable preferential treatment by careful scrutiny of the contract under which mutual corporate services are charged to Atlantic. *RA-19,* p. 5.

Ratepayer Advocate witness David Peterson has pointed out that the lack of direct billing and assignment presents a problem for regulators charged with protecting the public interest. In particular, although PHISC does not yet offer services to all of the PHI companies, PHISC's predecessor, CRP, allocated rather than directly assigned or directly charged an overwhelming majority of total costs. In fact, according to Mr. Peterson, the percentage of CRP costs that were directly billed to Atlantic in 2002 was only 18%, $16.6 million out of a total of $92.6 million. The remaining $76 million was indirectly billed using allocation factors. *RA-19,* p. 6. Ideally, the numbers should be reversed, according to Mr. Peterson – 70-80% of Service Company billings should be assigned or directly charged, and less than 30% should be allocated.

The Company claims first that, because many of the allocated costs are related solely to the regulated utilities, there is no cross-subsidization issue. However, it is equally problematic if ratepayers of one regulated utility are charged for services provided to another regulated utility's ratepayers.

Secondly, the Company claims that the use of allocations is overall no less accurate than direct billing. However, the Ratepayer Advocate believes that allocation methods should be used only as a fallback position if it is not possible to directly assign costs. By their very nature, allocation methods are imprecise and arbitrary. Therefore, Mr. Peterson has recommended that the Company further protect the ratepayers by doing whatever possible to expand the categories of costs and activities that are directly assignable. *RA-19*, p. 7.

In order to prevent ratepayer cross-subsidization and to bring the Company in line with other New Jersey utilities, the Ratepayer Advocate recommends that no less than 70% (and preferably 80% or more) of PHISC's billings should be assigned or directly charged.

B. The Board's Procedures for Capitalization and Depreciation Should Be Followed and Reflected Separately in the Service Agreement.

The Ratepayer Advocate urges Your Honor and the Board to make several adjustments to the Service Agreement regarding the pricing for the capital cost of assets purchased by PHISC for use by Atlantic and the other affiliates. First, pricing for capital costs of assets is not spelled out in the Service Agreement. The Company should verify in writing that the acquisition costs of the assets purchased by the Service Company were capitalized according to the Board's capitalization policy for Atlantic. Second, assets acquired by the Service Company for Atlantic should be depreciated using lives and methods approved for similar property owned by Atlantic, rather than the Company's current method of using generally accepted accounting principles. Finally, the rate of return on assets that PHISC acquires for use by Atlantic should be based on Atlantic's authorized rate of return, unless the asset can be financed at a lower rate and the benefit resulting from such financing can be passed along to ratepayers.

Ratepayers should be in no worse position regarding rate responsibility for assets than if Atlantic had bought the assets itself rather than going through the Service Company. Regardless of actual ownership, the costs and depreciation rates of these assets should be handled according to the Board's rate-making treatment.

C. The Atlantic Commitment to Allocate a Minimum of 10% of the Corporate Overhead to the Holding Company Should Be Written into the Service Agreement.

At the evidentiary hearing on April 2, 2004, the Ratepayer Advocate was made aware of the Company policy of allocating 10% of indirect corporate governance costs first to PHI before the blended factor for allocation is applied to the utility client. T816:L8-14. According to the Company, "sometime in the next year" the Service Agreement will be amended to reflect the 10% allocation or "whatever" the Company is doing, as they "are also looking at other ways of doing it." T817:L17-25.

The Ratepayer Advocate supports the 10% allocation as stated by Mr. Lavin at the April 2 evidentiary hearing.

D. Your Honor and the Board Should Require the Implementation of Reporting and Notification Requirements for Phisc as Suggested by the Ratepayer Advocate.

In its Direct Testimony, the Ratepayer Advocate recommended incorporating several reporting and notification procedures into the amended Service Agreement. As noted by Ratepayer Advocate witness Peterson, increased reporting requirements are necessary because: 1) the charges of PHISC to Atlantic are substantial; 2) this is the Board's first experience working with the Pepco Companies; and 3) the always-possible unforeseen circumstances that could cause changes in the allocation factors and, therefore, Atlantic's revenue requirement. Accordingly, Board Staff, the Ratepayer Advocate, and the Board should receive notification of any changes to the Service Agreement and any changes in the underlying bases of cost allocation.

The Company indicated that it "is not opposed", to implementation of these recommendations, "based on its initial interpretation". *P-28*, p. 11. The Ratepayer Advocate recommendations are summarized as follows:

a. a standard policy to apprise the Board of new participants to the Service Agreement in order that appropriate overhead allocation factors can be monitored;
b. a procedure by which the Board and Ratepayer Advocate are sent copies of letters to the SEC regarding any proposed changes to the Service Agreement;
c. copies to the Board and Ratepayer Advocate of all reports that relate to internal audits of PHISC;
d. nofication to the Board and Ratepayer Advocate when an SEC audit is about to be performed upon PHISC;
e. reasonable access for the Board and Ratepayer Advocate to PHISC books and records and to those of other PHI companies that transact with Atlantic; and
f. conditioning Board approval of the Service Agreement upon a commitment from Atlantic that issues affecting New Jersey ratepayers would be subject to Board jurisdiction and that the Service Agreement would be subject to review in the context of any future competitive service audits, with full participation of the Ratepayer Advocate.

RA-19, p. 12.

CONCLUSION

As demonstrated above and in the testimony of Ratepayer Advocate witnesses, the Ratepayer Advocate respectfully submits that Your Honor and the Board should adopt the following recommendations:

(1) Atlantic's return on equity should be set at 9.25% with an overall rate of return of 7.66%, reflecting adjustments to the Company's *pro forma* capital structure for the inclusion of short-term debt, the unamortized balance of call premiums, new debt issuances and refinancings;

(2) The appropriate *pro forma* rate base amounts to $ 614,769,000 which is $33,305,000 lower than the *pro forma* rate base proposed by the Company;

(3) The appropriate *pro forma* operating income amounts to $50,938,000 which represents a $9,395,000 increase over the Company's proposed *pro forma* operating income of $41,543,000;

(4) Your Honor and the Board should exclude recovery for the Cumberland Certificate of Need and the nuclear related costs from the proposed RARC;

(5) Atlantic's depreciation expense amount should properly reflect the Ratepayer Advocate's recommended adjustments to the company's 20-year old depreciation rates and the use of the net salvage allowance approach;

(6) Your Honor and the Board should reject the Company's Revenue Allocation Proposal and allocate any rate decrease or rate increase using the Company's flawed cost of service study only as a guide;

(7) The imposition of penalties for failure to minimum reliability performance levels; and

(8) The Service Agreement should be modified to adopt the Ratepayer Advocate's recommendations that direct assignment and direct billing using standard rates should account for at least 70 percent of the total Service Company billing and that ten percent of indirect corporate overhead costs should be assigned to PHI before allocating these costs to member companies.

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