STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE GAIL M. COOKSON

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF AN INCREASE IN ELECTRIC AND GAS RATES AND FOR CHANGES IN THE TARIFFS FOR ELECTRIC AND GAS SERVICE, B.P.U.N.J. NO.16 ELECTRIC AND B.P.U.N.J. NO. 16 GAS, AND FOR CHANGES IN DEPRECIATION RATES, PURSUANT TO N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF	))))))))))))	**BPU DOCKET NOS. ER18010029 and GR18010030** **OAL DOCKET NO. PUC 01151-18**

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

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

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

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

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

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

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

Q. Have you previously testified in regulatory proceedings?

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

Q. What is your educational background?

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

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On January 12, 2018, Public Service Electric and Gas Company ("PSE&G" or "Company") filed a Petition with the New Jersey Board of Public Utilities ("BPU" or "Board") requesting changes in its base distribution rates for electric and gas service. The Columbia Group, Inc. was engaged by The New Jersey Division of Rate Counsel ("Rate Counsel") to review the Company's Petition and to provide recommendations to the BPU regarding the Company's revenue requirement claims. In addition, I was engaged to examine certain issues relating to the Company's proposed treatment of refunds to customers resulting from the Tax Cut and Jobs Act of 2017 ("TCJA"). In developing my recommendations, I relied upon the cost of capital and capital structure testimony of Matthew I. Kahal, and on the depreciation testimony of James Garren. In addition, I relied in part on the testimonies filed by Charles Salamone and Maximilian Chang on certain electric engineering issues and by Edward McGee on certain gas engineering issues. Testimony on behalf of Rate Counsel is also being filed by David Peterson on class cost of service/rate design issues, by Susan Baldwin on customer service issues, and by Dr. David Dismukes on the Company's proposed decoupling mechanism.

Q. Please provide a brief summary of the Company's filing.

A. In its Original Petition filed on January 12, 2018, PSE&G requested an electric base revenue increase of $110.997 million and a gas base revenue increase of $186.695 million. In addition, PSE&G requested that the Board authorize the Company to establish a Tax Adjustment Credit ("TAC") mechanism, to flow back to customers several credits associated with the TCJA. PSE&G proposed that the amortization periods utilized in the TAC be subject to change each year, at the Company's discretion, in order to permit the Company to better manage its cash flows. Thus, the actual credit flowing through the TAC to customers would have changed each year under the Company's original proposal. PSE&G proposed that the amount of the TAC should initially be set at ($84.429) million for electric and at ($118.539) million for gas. Therefore, the Company initially proposed a net revenue increase of $26.568 million for electric customers and an increase of $68.156 million for gas customers, as shown below:

	Electric (Million)	Gas (Million)	Total Company (Million)
Base Revenue Increase	$110.997	$186.695	$297.692
Initial TAC	($84.429)	($118.539)	($202.968)
Net Revenue Change	$26.568	$68.156	$94.724

The Company's initial filing resulted in a net electric increase of approximately $27 million, or 0.49%, and a net gas increase of approximately $68 million or 2.97%. The Company's Petition was based on a Test Year ending June 30, 2018. As filed, the Petition reflected five months of actual data and seven months of projected results. PSE&G's filing was based on an overall cost of capital of 7.40%, which included 54% common equity at a cost of 10.3%. The Company also proposed to implement a Green Enabling Mechanism ("GEM"), which would effectively decouple revenues from utility sales.

The Company's original filing assumed that the current base rates, which reflected a 35% corporate federal income tax rate, would remain in effect until an order was issued in this base rate case. However, on April 1, 2018, PSE&G reduced its electric rates by $70.651 million and reduced its gas rates by approximately $42.891 million in response to a Commission Order in Docket No. AX18010001. This Order directed the Company to reduce its rates to reflect the prospective impact of the reduction in the corporate federal income tax rate, from 35% to 21%, which was effective January 1, 2018.

On May 14, 2018, the Company filed an update to its Petition, which reflected actual results through March 2018 and projections for the last three months of the Test Year ("9 and 3 Update"). In addition, the Company's 9 and 3 Update reflected the impact of the rate reduction that was effective on April 1, 2018.

Following are the components of the Company's 9 and 3 Update:

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	Electric (Million)	Gas (Million)	Total Company (Million)
Base Revenue Increase	$199.787	$237.551	$437.338
Initial TAC	($65.901)	($130.035)	($195.936)
Net Revenue Change	$133.886	$107.516	$241.402

Subsequent to the filing of the 9 and 3 Update, the Company notified the parties that it was revising its proposed TAC mechanism. The Company further revised its TAC credit in the response to RCR-A-140, which was filed on July 20, 2018. As discussed in that response, the Company is now proposing essentially a levelized TAC mechanism. This new proposal reduced the initial electric utility credit to ($39.0) million and increased the initial gas utility credit to ($152.7) million.

Q. What did you utilize as the starting point for your analysis?

A. Except for issues impacting the TAC, my testimony is based on the Company's 9 and 3 Update. My adjustments relating to the TAC are based on the update provided in the response to RCR-A-140. It should be noted that my recommendations regarding the TAC are policy recommendations and reflect the balances provided in RCR-A-140. I have not independently verified these starting balances. Additional quantitative tax adjustments may be provided by other interveners in this case or elicited at the hearings. In addition, additional adjustments may be identified once the Company finalizes its 2017 income tax return. Therefore, I reserve the right to make additional adjustments to the tax balances used in my testimony.

In addition, PSE&G will be filing an additional update once it has a full twelve months of actual Test Year data ("12+0 Update"). My recommended revenue requirement will be updated once PSE&G files its 12+0 Update.

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

A. The most significant issues driving the Company's claims in this case are its request for an authorized cost of equity of 10.3%; the Company's proposal to implement significant increases in electric and gas depreciation rates, its proposal to deviate from well-adopted accounting principles in determining its pension expense for ratemaking purposes, its claim for recovery of significant incentive compensation costs, and its proposal to establish a new regulatory mechanism to handle certain income tax issues, i.e., the TAC.

III. SUMMARY OF CONCLUSIONS

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

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

1. The twelve months ending June 30, 2018 is a reasonable Test Year to use in this case to evaluate the reasonableness of the Company's claims.
2. Based on the testimony of Mr. Kahal, the Company has a cost of equity of 9.0% and an overall cost of capital of 6.62%.
3. PSE&G has pro forma electric distribution rate base of $5.465 billion (see Schedule ACC-3E) and a pro forma gas distribution rate base of $3.880 billion (see Schedule ACC-3G).[1]
4. The Company has pro forma electric distribution operating income at present rates of $334.468 million (see Schedule ACC-11E) and pro forma gas distribution operating income at present rates of $233.830 million (see Schedule ACC-12G).
5. The Board should deny the Company's request to establish a new mechanism to handle tax credits associated with the TCJA. Instead, these tax credits should be included in base rates.
6. PSE&G has a pro forma, electric distribution revenue surplus of $48.868 million

[1] Schedules ACC-1E and ACC-35E are summary schedules, Schedule ACC-2E is a cost of capital schedule, Schedules ACC-3E to ACC-10E are rate base schedules, and Schedules ACC-11E to ACC-34E are operating income schedules. Similarly, Schedules ACC-1G and ACC-34G are summary schedules, Schedule ACC-2G is a cost of capital schedule, Schedules ACC-3G to ACC-11G are rate base schedules, and Schedules ACC-12G to ACC-33G are operating income schedules.

(see Schedule ACC-1E) and a pro forma, gas distribution revenue surplus of $106.743 million (see Schedule ACC-1G).

7. PSE&G should refund to customers the overcollection in federal income taxes of $5.641 million for the electric utility and of $21.789 million for the gas utility for the period January 1, 2018 through March 31, 2018. These amounts should be refunded with interest within 60 days of an Order being issued in this case. The interest should be computed using PSE&G's short-term debt rate.

8. My revenue requirement recommendation may be updated once the Company files its actual Test Year results, based on the twelve months ending June 30, 2018.

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

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

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

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	45.51%	4.03%	1.83%
Common Equity	54.00%	10.30%	5.56%
Customer Deposits	0.49%	0.87%	0.00%
Total	100.00%		7.39%

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

A. As shown on Schedule MIK-1 of Mr. Kahal's testimony, Rate Counsel is recommending an overall cost of capital for PSE&G of 6.62% based on the following capital structure and cost rates:

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	46.36%	3.96%	1.84%
Common Equity	53.16%	9.00%	4.78%
Customer Deposits	0.48%	0.87%	0.00%
Total	100.00%		6.62%

Mr. Kahal is recommending a slightly different capital structure and a slightly lower cost of debt for the Company. In addition, he is recommending that the Board authorize a cost of equity of 9.0% for PSE&G. Mr. Kahal's adjustment results in a pro forma overall cost of capital of 6.62%, which is the overall cost of capital that I have used to determine the Company's pro forma required income, as shown on summary Schedules ACC-1E and ACC-1G, based on my recommended rate base. I then compared this required income to pro forma income at present rates to determine the Company's need for rate relief.

V. RATE BASE ISSUES

A. Utility Plant-in-Service

Q. How did PSE&G determine its utility plant-in-service claim in this case?

A. The Company began with its estimated utility plant-in-service balances at June 30, 2018, the end of the Test Year in this case. As shown on Exhibit P-2, Schedule SSJ-07 R-1, the Company included estimated Test Year additions of $968.550 million for the electric utility and of $943.174 million for the gas utility. In addition, PSE&G then made post-test year adjustments to reflect projected plant-in-service additions through December 31, 2018. The Company included $154.809 million of post-test year electric plant additions and $338.340 million of post-test year gas plant additions in its claim.

In addition to adjustments relating to post-test year plant additions, PSE&G made rate base adjustments to reflect projected plant retirements, projected depreciation reserve additions, and projected additions to the deferred income tax reserve through December 31, 2018.

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

A. Yes, I am recommending two adjustments. First, I recommend that the BPU eliminate all post-test year plant additions from the Company's rate base. Second, I recommend that the BPU eliminate the TrakSmart program from the Company's rate base claim in this case.

Q. What is the basis for your recommendation to exclude all post-test year plant additions from rate base?

A. The Company's claim results in a mismatch among the components of the regulatory triad used to set rates in this case and is inconsistent with BPU precedent regarding the inclusion of post-test year plant additions in rate base. Ratesetting is based on a regulatory triad that attempts to match revenues, expenses, and rate base investment during a twelve-month test year period. In addition, while the Board has authorized certain post-test year plant adjustments in certain cases, the Company did not attempt to limit post-test year plant additions to projects that meet the criteria outlined by the Board for such ratemaking treatment.

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

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

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

measurable changes to the test year, by definition, reflect future contingencies; but in order to prevail, petitioner must quantify such adjustments by reliable forecasting techniques reflected in the record.

It is clear that the Company has not met the criteria specified by the BPU for the inclusion of post-test year projects in rate base. PSE&G has not limited its post-test year plant-in-service claim to projects that are "major in nature and consequence." Instead, the Company has included all projected plant additions through December 2018 in a variety of categories without attempting to distinguish those that may meet the "major in nature and consequence" criteria. This includes $129.644 of electric plant distribution projects and $303.937 of gas plant distribution projects, much of which relate to blanket projects.

Q. What do you recommend?

A. Since PSE&G has not demonstrated that its post-test year projects meet the requirements laid out in the Elizabethtown decision, I recommend that all post-test year plant additions be eliminated from the Company's claim. Therefore, my revenue requirement recommendation reflects the Company's projected June 30, 2018 utility plant-in-service balances, as claimed in the 9 and 3 Update. My adjustment is shown in Schedule ACC-4E and Schedule ACC-4G.

Q. Did you make corresponding adjustments associated with retirements, accumulated depreciation and accumulated deferred income taxes?

A. Yes, I did. Since I have eliminated post-test year plant additions from the Company's rate base, it is necessary to make corresponding adjustments to remove the post-test year adjustments related to retirements, accumulated depreciation and accumulated deferred income taxes. Since my recommendation is based on plant balances at June 30, 2018, the adjustments shown in Schedules ACC-4E and 4G include the impact of removing post-test year plant retirements. In addition, at Schedules ACC-7E and ACC-7G I have eliminated the Company's proposed post-test year adjustment to the depreciation reserve. At Schedules ACC-9E and ACC-9G I have eliminated the Company's proposed post-test year adjustment to the accumulated deferred income tax reserve.

Q. Are there any other rate base adjustments necessary to reflect Rate Counsel's recommendation to eliminate post-test year plant additions?

A. Yes, there is one additional adjustment for the gas utility. As shown in Schedule SSJ-15, R-1, the Company reduced rate base to reflect the third roll-in of the Gas System Modernization Program ("GSMP"). The amount of the adjustment at June 30, 2018 is a rate base reduction of $153,965, while the amount of the adjustment at December 31, 2018 is a rate base reduction of $215,522. Since I am recommending that post-test year plant adjustments be disallowed, it is necessary to also eliminate the Company's post-test year adjustment related to GSMP roll-in #3. Therefore, at Schedule ACC-11G, I have made an adjustment to reflect the June 30, 2018 balance associated with the GSMP roll-in #3 instead of the December 31, 2018 balance included in the Company's filing. With this adjustment, all components of the Company's rate base are synchronized at June 30, 2018, the end of the Test Year in this case.

Q. What is the TrakSmart Program?

A. TrakSmart is a software application that the Company utilizes to manage, track, and report on its energy efficiency programs. Costs related to this program are recovered through a clause or surcharge mechanism, not through base distribution rates. In the response to RCR-A-133, the Company indicated that it had inadvertently included the unamortized costs of the TrakSmart program in rate base. Therefore, at Schedule ACC-5E and ACC-5G, I have made adjustments to eliminate the net capital costs associated with the TrakSmart program from rate base. Since the Company indicated in response to RCR-A-133 that it did not include the associated TrakSmart amortization expense in its claim, it was not necessary to make a corresponding adjustment to amortization expense.

Q. Other than your recommendation with regard to the TrakSmart Program, are you recommending any other adjustments to the Company's Test Year plant-in-service claims?

A. No, not at this time. However, Rate Counsel witnesses Charles Salamone and Maximilian Chang have expressed concerns about several aspects of the American Dream project. It is my understanding that all Test Year plant balances at June 30, 2018 represent projects that are completed and placed into service, subject to the 12 and 0 Update. Therefore, I am assuming that no costs associated with the American Dream Project are actually included in the Company's June 30, 2018 rate base claim. To the extent that the actual Test Year rate base claim does include some plant additions associated with American Dream, an additional adjustment may be appropriate.

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

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

A. Yes, the Company has included $495,000 of electric plant held for future use and $96,000 of gas plant held for future use in its rate base claim.

Q. What is plant held for future use?

A. Plant held for future use is plant that is not currently used in the provision of utility service to customers but which the Company claims has some potential to be used in the future to serve customers. As described in the response to RCR-A-95, the plant held for future use that the Company included in rate base consists of land for future substation sites and gas mains installed for anticipated future growth. None of this plant is expected to be in-service prior to 2023.

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

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

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

Q. What is cash working capital?

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

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

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

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

A. There are two components to the Company's cash working capital claim. First, PSE&G developed a proposed cash working capital allowance based on the results of its lead-lag study. The lead-lag study utilized revenues and expenses for the 2016 calendar year in order to determine the lead and lag days. The resulting lead-lag days were then applied to the Company's proposed revenue requirement in order to determine the first part of its cash working capital claim.

In addition to the cash working capital allowance developed from the lead-lag study, PSE&G also included an additional cash working capital allowance, based on the net difference between current assets and current liabilities over a thirteen-month period, ending March 31, 2018. The Company's total electric and gas cash working capital claim is shown below:

	Electric (Millions)	Gas (Millions)
Lead-Lag Study	$338.826	$203.245
Net Assets and Liabilities	$66.164	$46.568
Total	$404.990	$249.813

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

A. Yes, I am recommending adjustments to both the Company's lead-lag study and to its claim to include an allowance for net assets and liabilities.

Q. Please discuss your recommended adjustments to the Company's lead-lag study.

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

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

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

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

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

Q. Why do you also reject the use of zero lag days for deferred tax expense?

A. This item is similar to depreciation expense in that deferred income taxes are, by definition, deferred and therefore they do not create a need for cash. Therefore, deferred tax expense is not properly includable in any form in the calculation of cash working capital.

Q. Please explain why you have rejected the Company's claim for zero lag days for operating income.

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

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

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

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

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

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

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

A. The lag in the payment of interest expense must be reflected in the cash working capital calculation so that ratepayers are compensated for providing a cost-free source of capital to PSE&G prior to the interest payments being made. In developing my adjustment, I included the interest expense at a lag of 91.25 days, which reflects semi-annual payments of interest.[2]

Q. Are you recommending any other adjustments to the Company's lead-lag study?

A. Yes, I am recommending an additional adjustment to the Company's revenue lag. In this case, PSE&G has included a revenue lag of 57.7 days. This includes a service lag of 15.3 days, a billing lag of 3.4 days, and a collection lag of 39.0 days. This revenue lag is significantly longer than the revenue lag filed in the Company's last base rate case. In response to S-OCI-PSEG-CWC-0001, the Company stated that the revenue lag filed in its last base rate case was 46.07 days, although this revenue lag was revised to 53.07 days as the case progressed. In addition, a billing lag of 0.0 days was included in the last case vs. a billing lag of 3.4 days in the current case.

I am recommending two adjustments to the revenue lag of 57.7 days reflected in the Company's lead-lag study. First, I am recommending that the service lag be reduced from 15.3 days to 15.2 days. As noted in Mr. Walker's testimony at page 10, his service lag of 15.3 days is based on 2016 data, which was a leap year. The correct service lag should therefore be 15.2 days (365 days / 12 months / 2). In addition, I am recommending that the Board adopt a billing lag of 0.0, consistent with the Company's claim in the last case. This would result in a total revenue lag of 54.2 days. While this is still higher than the revenue lag of 53.07 from the last case, it is more in line with that case than the billing lag of 57.7 days included in the original Petition. My recommendation also reflects the

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

fact that PSE&G controls the lag in the billing of customers once meters are read. Therefore, the Company should not utilize a delay in billing as an excuse to increase its cash working capital claim. At Schedules ACC-8E and ACC-8G, I have reflected a cash working capital allowance that includes a revenue lag of 54.2 days, as well as the other adjustments to the lead-lag study discussed above.

Q. Have you included the Company's net assets and liabilities as an additional component to the Company's cash working capital requirement?

A. No, I have not. There are various ways in which a utility's cash working capital requirement can be determined. The most common method utilizes a lead-lag study to identify the net leads and lags associated with obtaining the cash necessary for the Company's cost of service. Another methodology assumes that the net difference between the Company's current assets and current liabilities is the amount of cash on hand that the Company needs to pay its bills. Regulatory commissions should use one of these two methods to determine a utility's need for cash working capital. But not both. The Company's methodology double counts its need for cash working capital. All components of the Company's cost of service that impact cash are already reflected in the Company's lead-lag study. If a lead-lag study is conducted, no further adjustment is necessary. Therefore, at Schedules ACC-8E and ACC-8G, I have limited my cash working capital allowance to the results of my lead-lag study recommendations, and excluded any additional claims related to net current assets or current liabilities.

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

A. I have eliminated the zero lag days used by the Company for depreciation and amortization, deferred taxes, and operating income and reflected the lag in the payment of interest expense. I have also utilized a net revenue lag of 54.2 days. In addition, I have eliminated the additional cash working capital claim related to net current assets and current liabilities, on the basis that any need for cash working capital is fully reflected in the lead-lag study results. My adjustments result in the required cash working capital allowances shown in Schedules ACC-8E and ACC-8G.

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

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

D. Consolidated Income Taxes

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

A. Yes, it does. PSE&G files its income taxes as part of a consolidated income tax group that includes the holding company, Public Service Enterprise Group, Inc. and all of its subsidiaries. By filing a consolidated return with the Internal Revenue Service ("IRS"), the tax loss benefits generated by one group member can be shared by the other consolidated group members, resulting in a reduction in the effective federal income tax rate. PSE&G has been a member of a consolidated income tax group since at least 1986 when the current Tax Allocation Agreement was executed by the group members.

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

A. Yes, it has. The BPU has traditionally flowed these benefits through to ratepayers. The issue of consolidated income tax adjustments has been thoroughly reviewed by both the Board and the New Jersey courts, both of whom have found that a consolidated income tax adjustment is appropriate.[3] In its decision in the 1991 Jersey Central Power and Light Company ("JCP&L") base rate case (BPU Docket No. ER91121820J), dated June 15, 1993, at pages 7-8, the BPU held that:

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

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

In a separate JCP&L base rate case filed in 2002, the Board's Final Order, dated May 14, 2004, (BPU Docket No. ER02080506) at page 45, stated:

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

The reality is that Public Service Enterprise Group, Inc. ("Enterprise"), PSE&G's parent company, has elected to file a consolidated income tax return for its subsidiaries, including PSE&G. Moreover, PSE&G has been a member of a consolidated income tax group since the Board first adopted consolidated income tax adjustments. Apparently, the filing of a consolidated tax return still offers advantages to PSE&G and members of the consolidated income tax group. Because Enterprise has elected to file a consolidated tax return for its member companies, including PSE&G, I believe it is a settled matter that the tax savings should be shared with utility ratepayers.

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

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

Q. How does Enterprise determine the actual amount of taxes paid by PSE&G to its parent each year?

A. The payment of taxes is governed by a Tax Sharing Agreement among the members of the consolidated income tax group. Pursuant to the agreement, PSE&G, and other subsidiaries with positive taxable income, pay the amount of their stand-alone tax liability to the parent company. Enterprise then pays the amount of taxes due by the consolidated group to the IRS. Any excess funds are used to compensate members of the consolidated income tax group with tax losses, to the extent that these tax losses can be used by the consolidated group. This arrangement therefore results in a contractual means which permits the regulated and profitable subsidiaries to subsidize unregulated and unprofitable ventures. These procedures transfer the excess amounts collected from ratepayers for income tax expense from the utility to the affiliates that generated the income tax losses, effectively resulting in a subsidization of the unregulated affiliates, and other unprofitable companies, by New Jersey ratepayers. In contrast, the consolidated income tax adjustment adopted by the BPU partially compensates ratepayers for this subsidization, by crediting ratepayers with carrying costs on these funds.

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

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

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

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

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

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

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

- A limited time period of five years over which the consolidated tax adjustment would be calculated,
- The savings allocated to the New Jersey utility would be further allocated, such that ratepayers received only 25% of the utility's share of the consolidated income tax benefit, and
- Transmission assets would not be included in the allocation.

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

Q. What is the status of Rate Counsel's appeal?

A. Rate Counsel's appeal was upheld by the Court. The Board has since proposed two sets of regulations on consolidated income taxes, but no final action has been taken.

Q. Did PSE&G include a consolidated income tax adjustment in this case?

A. Yes, the Company included a consolidated income tax adjustment based on the methodology approved by the Board in the BPU Docket No. EO12121072. This resulted in a rate base reduction of $555,000 for the electric utility and a rate base reduction of $157,000 for the gas utility, as shown in Exhibit P-2, Schedule SSJ-03, R-1.

Q. What do you recommend?

A. I have based my adjustment on the RECO methodology that has traditionally been used by the Board. To quantify my adjustment, I utilized the tax losses and taxable income for each Enterprise subsidiary over a period of twenty years. This is the period during which tax losses can be carried forward pursuant to IRS regulations. In addition, I have not further allocated any of the utility's share of the consolidated income tax benefit to shareholders. Based on my recommended methodology, only 31.52% of the consolidated income tax benefit is allocated to New Jersey ratepayers, which is then further allocated between electric and gas. Thus, shareholders are already receiving all such benefits that would otherwise be allocated to unregulated entities and/or to utilities in states that do not recognize a consolidated income tax adjustment for ratemaking purposes. Finally, I have not excluded transmission assets from the calculation. As noted in Rate Counsel's 2015 appeal, excluding transmission assets from the calculation would prevent ratepayers from receiving the tax benefit that accrued from ratepayer funds. In addition, it treats the New Jersey electric utilities differently from the other utilities in the state. Therefore, I have not excluded transmission assets from the calculation of my consolidated income tax adjustment.

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

A. My consolidated income tax adjustment results in a rate base deduction of $12.993 million for the electric utility and of $3.665 million for the gas utility, as shown in Schedules ACC-10E and 10G.

E. Summary of Rate Base Issues

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

A. My recommended adjustments reduce the Company's electric rate base from $5,672,133, as reflected in its 9 and 3 Update, to $5,464,734, as summarized on Schedule ACC-3E. In addition, my recommended adjustments reduce the Company's gas rate base from

$4,165,737, as reflected in its 9 and 3 Update, to $3,879,923, as summarized on Schedule ACC-3G.

VI. OPERATING INCOME ISSUES

A. Pro Forma Revenues

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

A. PSE&G began with its estimated Test Year revenues. For the electric utility, the Company then normalized its revenues for normal weather conditions. In addition, it made adjustments to its pro forma electric revenues to annualize increases associated with Energy Strong roll-ins that took effect prior to new rates being established in this case. With regard to the gas utility, the Company did not include a weather normalization adjustment because the gas utility has a weather normalization clause that adjusts revenues for normal weather conditions. The Company did make adjustments to gas revenues to annualize roll-ins associated with Energy Strong and GSMP adjustments prior to the effective date of new rates.

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

A. Yes, I am recommending one adjustment relating to the Company's weather normalization adjustment for the electric utility.

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

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

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

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

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

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

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

A. There are a few reasons. First, longer time periods tend to average out extreme weather and temperature much better than shorter periods. Second, a shorter time period may fail to include extreme weather in computing average degree days. It is normal and customary to have a very cold or a very warm year every so often, and the data base of thirty years should include these extremes.

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

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

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

A. No, it is not. The purpose of a weather normalization adjustment is not to forecast or predict weather for a particular year. Regulatory commissions are regulators, not weather forecasters. The purpose of a weather normalization adjustment is instead to determine what customer usage would be, assuming "normal" weather.

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

A. Yes, it is. However, permanent changes in weather patterns are likely to take place over a long period of time. NOAA has determined that data from a period of 30 years satisfactorily represents normal weather. To the extent weather patterns do exhibit a permanent change over time, such changes will be reflected in the 30-year NOAA data. Moreover, the BPU should not confuse the determination of "normal" weather with the issue of how customers will react to variations from normal weather. Therefore, the BPU should be mindful of the difference between changes in weather patterns over time and changes in usage patterns over time. The two are not the same. While NOAA uses a 30-year period to determine normal degree days, NOAA is not involved in forecasting how energy sales are likely to be impacted due to variations in degree days. Due to conservation efforts, more efficient appliances and other factors, it is entirely possible that the impact of variations in degree days is different in 2017 than it was in 1987. My recommendation that the BPU utilize a 30-year standard does not prevent the utility or other parties from presenting arguments regarding the *impact* of weather variations on energy usage.

Q. How did you quantify your adjustment?

A. In its filing, the Company's weather normalization adjustment increases operating revenue at present rates by $5,840,000. In response to RCR-A-127, the Company indicated that the use of a 30-year normal would have increased operating revenue at present rates by $5,260,000. Therefore, the use of the 30-year weather normalization will actually decrease the Company's pro forma revenue at present rates by $580,000, resulting in a slightly higher revenue increase. At Schedule ACC-12E, I have made an adjustment to reflect a weather normalization adjustment based on the use of a 30-year period to determine normal weather.

Q. Are you making any recommendation about the weather normalization methodology currently used in the gas utility's weather normalization clause?

A. No, it is my understanding that the gas utility's weather normalization clause, which uses a 20-year period to determine normal weather, has been in operation for some time. While I oppose weather normalization clauses on general principles, I am not making any recommendation in this case regarding the operation of the gas utility's weather normalization adjustment clause or the underlying calculation of that adjustment.

B. <u>Salary and Wage Expense</u>

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

A. To develop its salary and wage claim, PSE&G first projected payroll costs for the twelve months ending June 30, 2018, the Test Year in this case. For bargaining employees, PSE&G then reflected a 3% increase, effective May 1, 2018, and another 3% increase effective September 1, 2019. For non-bargaining employees, PSE&G reflected 3% annual increases effective April 1, 2018 and April 1, 2019. The Company's salary and wage adjustments resulted in an increase of $4,379,000 for the electric utility and of $6,634,000 for the gas utility.

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

A. Yes, I am recommending two adjustments. First, the Company did not estimate costs for the last quarter of the Test Year by annualizing the first nine months of actual salary and wage expense. Instead, the last three months of the Test Year were based on budgeted data. Since actual employees can vary significantly from budget, and since many employees allocate their time among various projects, including projects that are not recovered in base rates, I believe it is more appropriate to estimate the last three months of the Test Year by annualizing the actual costs for the first nine months.

Second, I recommend that projected 2019 increases be disallowed. The Company has included increases projected for April 1, 2019 and September 1, 2019. These adjustments reach too far beyond the end of the Test Year and distort the regulatory triad of synchronizing rate base, revenues, and expenses. Therefore, I recommend that the BPU reject both of these 2019 adjustments. My salary and wage adjustments are shown in Schedules ACC-13E and ACC-13G.

C. Incentive Compensation Plan Expense

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

A. The Company has two incentive compensation programs for non-officer, non-bargaining employees, as described in the response to RCR-A-51. First, the Company has a Performance Incentive Plan ("PIP"), which is an annual short-term cash incentive plan. The PIP award is based on four factors: a Corporate Financial Factor, a Business Unit Financial Factor, a Business Unit Scorecard, and Strategic Goals set at the corporate level. The relative weightings of each of the four factors differs depending on the organization and on the level of the employee within the organization. For example, incentive compensation for PSE&G employees up to manager level is not tied to either the Corporate Financial Factor or the Business Unit Financial Factor. Approximately 50% of PIP awards at the level of Director and above are based on financial parameters. With regard to Service Company employees, 30%-50% of the weighting is based on the Corporate Financial Factor, depending on the employee level. Generally, the higher up one goes in each organization, the more weight is given to financial factors.

Non-officer, non-bargaining employees at the Director level or above are also eligible for an equity-based Long-Term Incentive Plan ("LTIP"). The LTIP is based purely on financial metrics. The awards are granted in the form of Restricted Stock Units ("RSUs") and Performance Stock Units ("PSUs"). These awards vest after three years.

The Company included the following costs for non-officer incentive compensation in its 9 and 3 Update:[4]

9 and 3 Update – Non Officer Incentive Compensation Expense

	PIP	LTIP	Total
Electric:			
Utility	$8,196,734	$670,288	$8,867,021
Service Company	$3,700,538	$722,567	$4,423,105
Total Electric	$11,897,271	$1,392,855	$13,290,127
Gas			
Utility	$7,458,200	$617,370	$8,075,570
Service Company	$3,558,427	$676,685	$4,235,111
Total Gas	$11,016,627	$1,294,055	$12,310,682

With regard to officers, the Company has three incentive compensation plans. The Senior Management Incentive Compensation Plan ("SMICP") and the Management Incentive Compensation Plan ("MICP") are cash incentive compensation plans that cover senior level officers and other officers respectively. These awards are based on the same four components as the PIP, except these awards are more heavily weighted toward financial goals. In addition, officers are also eligible for an equity-based LTIP, which is based on financial parameters. The incentive compensation costs included in the 9 and 3 Update for officers are[5]:

4 Per the response to RCR-A-141.
5 Per the response to RCR-A-142.

9 and 3 Update – Officer Incentive Compensation Expense

	SMICP	MICP	LTIP	Total
Electric:				
Utility	$173,615	$112,249	$939,657	$1,225,520
Service Company	$532.667	$337.617	$3,135,760	$4,006,044
Total Electric	$706,282	$449,866	$4,075,417	$5,231,565
Gas				
Utility	$157,972	$102,135	$865,473	$1,125,580
Service Company	$512,212	$324,652	$2,936,640	$3,773,503
Total Gas	$670,184	$426,786	$3,802,113	$4,899,084

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

A. No, I do not. I have several concerns about these types of programs related to the inclusion of these costs in rates. PSE&G employees are well compensated independent of incentive compensation awards. Non-bargaining employees have consistently been awarded annual payroll increases of 3.0% in each of the past four years.[6] Moreover, according to the response to S-OCI-PSEG-REV-67, the average salary and wage compensation for PSE&G employees was $118,470 in 2016. Even though it appears that these averages include incentive awards, it is still apparent that PSE&G employees are well-paid. Thus, there is no indication that the employees of PSE&G are underpaid or that the Company would have difficulty attracting qualified employees in the absence of

6 Per the response to RCR-A-42.

these programs.

In addition, officers are certainly well compensated. As shown in the 2018 Proxy Statement[7] Mr. Izzo's base salary was $1.3 million in 2017, and the average base salary for the other top executive officers was approximately $550,000. In addition to these salaries, officers received equity awards ranging from $425,059 in the case of Mr. DiRisio (President of Services) to $6.5 million in the case of Mr. Izzo. Non-equity incentive compensation added another $1.8 million to Mr. Izzo's compensation, with other officers averaging non-equity incentive awards of $451,600.

Q. Has the BPU previously addressed the issue of incentive compensation costs?

A. Yes. The 2000 Middlesex Water Company base rate case reflects that:

> Staff was persuaded by the arguments of the RPA [(Ratepayer Advocate)] that, at this time, the incentive compensation expenses should be not be recovered from ratepayers. According to the record, incentive compensation expenses have tripled since 1995. In addition, the record also indicates that the bonuses are significantly impacted by the Company achieving financial performance goals. These facts lend strength to the RPA's position that it is inappropriate for the Company to request recovery of bonuses in rates at this time.[8]

The Administrative Law Judge ("ALJ") in that case initially recommended that Middlesex be permitted to recover 50% of its incentive compensation costs in rates. However, the BPU rejected the ALJ's recommendation and instead ordered that 100% of

7 See: http://www.ezodproxy.com/pseg/2018/proxy/images/PSEG-Proxy2018.pdf

8 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, 2001 N.J. PUC LEXIS 52, p. 61-62, (June 6, 2001).

these costs be disallowed.[9]

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

A. Yes, it does. As discussed on page 55 of Mr. Jennings' testimony, for the past few years PSE&G has utilized Mercer Consulting to evaluate its practices and provide information on compensation at other companies to use as a benchmark for its compensation programs. However, the use of such benchmarks has a detrimental effect on ratepayers as compensation costs spiral, especially at the executive level.

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

A. Companies state that they must benchmark their compensation in order to be competitive. However, such benchmarking actually results in ever-increasing executive compensation levels. This is because companies generally target their compensation to the 50th percentile of companies in the proxy group selected for benchmarking. Mr. Jennings testified on page 58 of his original testimony that "[o]ur compensation philosophy is to target total compensation at the median of companies we compete with for talent." Such practices tend to escalate increases in compensation, especially for highly-paid officers. These studies compare the subject company's compensation to compensation in a broad range of other firms. Since most companies do not want to find themselves in the lower

9 Id. at 64.

half of the benchmark group, companies that typically fall below the average raise their compensation – and hence the average of the benchmark companies continually increases. This sets off a chain of events that results in ever-increasing compensation levels as additional companies must increase their compensation levels to avoid falling below the 50^{th} percentile. The BPU should be particularly wary of any compensation plans that utilities attempt to justify by means of comparison to benchmark studies. It is not surprising that concurrent with the practice of benchmarking, executive compensation levels have risen dramatically over the past few years.

Q. What do you recommend?

A. I recommend that the BPU disallow at least 50% of the Company's claim for non-officer incentive compensation awards. The Company's employees are already well compensated, and the level of service being received by New Jersey ratepayers does not justify the payment of additional incentive awards. I have not disallowed 100% of these costs because the Company does consider non-financial factors in the incentive compensation awards made to many of its non-officer employees. My adjustment to disallow 50% of the non-officer incentive compensation costs is shown in Schedules ACC-14E and ACC-14G.

In addition, I recommend that 100% of the Company's claim for officer incentive compensation awards also be denied. My adjustment to eliminate officer incentive compensation costs is also shown in Schedules ACC-14E and ACC-14G. Officer incentive compensation awards are heavily weighted toward financial benchmarks. Moreover, these officers are already well compensated in their base salaries. Therefore, I believe it is appropriate to eliminate 100% of the officer incentive compensation awards reflected in the Company's filing.

Finally, while I have eliminated only 50% of the incentive compensation awards for non-officers, the BPU may want to consider eliminating 100% of these costs from regulated utility rates. Many of the non-financial benchmarks utilized to award incentive compensation are operational parameters that ratepayers have a right to expect – parameters such as reliability and customer service standards. Therefore, the BPU may determine that even these operational parameters do not justify the recovery of a portion of these PIP awards from ratepayers. In that case, I would not be opposed to the BPU eliminating 100% of these costs from the Company's revenue requirement.

D. <u>Payroll Tax Expense</u>

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

A. Since I am recommending adjustments to the Company's claims for salaries and wages and incentive compensation costs, it is necessary to make a corresponding adjustment to eliminate certain payroll taxes from the Company's revenue requirement claim. At Schedules ACC-15E and ACC-15G, I have eliminated payroll taxes associated with my recommended salary and wage adjustments and with my incentive compensation adjustments. To quantify my payroll tax adjustment, I utilized the pro forma payroll tax rate of 6.95%, which was the composite rate reflected in the Company's filing, and applied it to my recommended adjustments for salaries and wages and for incentive compensation program costs.

E. <u>Fringe Benefit Expense</u>

Q. What costs are included in the Company's adjustment relating to fringe benefits?

A. As shown on Exhibit P-2, Schedule SSJ-30, R-1, the Company's fringe benefit claim includes costs for Medical, Dental, and Vision benefits, Pension and Other Post-Employment Benefit ("OPEB") expense, Group Life and Disability Insurance, Savings Plans, Workers Compensation, and various other benefit costs.

Q. How did the Company develop its Fringe Benefits Expense claim in this case?

A. With the exception of Pension Expense, which will be discussed in more detail below, the Company included a projected "Rate Year" expense in its filing. The Rate Year was developed by combining three months of projected 2018 costs and nine months of projected 2019 costs.

Q. Is the Company's Fringe Benefit expense claim based on actual Test Year costs?

A. No, it is not. The estimates for the last three months of 2018 are based on the budgeted average monthly costs for the 2018 calendar year, which are generally higher than the actual Test Year costs. Similarly, the 2019 costs are based on the 2019 budget.

Therefore, the Company's post-test year adjustments are speculative and do not meet the known and measurable standard required for post-test year adjustments. In addition, the Company's Rate Year claim includes costs through September 2019, a full fifteen months after the end of the Test Year in this case.

Moreover, it is interesting to note that Fringe Benefit costs do not necessarily increase each year. As shown in the response to RCR-A-18, the Company's Fringe Benefit costs excluding pensions have decreased from 2015 to 2017, from $100.379 million in 2015 to $87.511 million in 2016 and to $85.853 million in 2017. Therefore, recent experience indicates that these costs do not necessarily increase each year.

Q. What do you recommend?

A. PSE&G's post-test year adjustments to Fringe Benefit expense are speculative and also reach far beyond the end of the Test Year in this case. For both of these reasons, I recommend that the Board deny PSE&G's post-test year adjustments to Fringe Benefit costs. My electric adjustment is shown in Schedule ACC-16E and my gas adjustment is shown in Schedule ACC-16G.

F. <u>Pension Expense</u>

Q. How is pension cost determined for ratemaking purposes?

A. There are two methodologies used by regulatory commissions to determine the appropriate amount of pension expense to include in utility rates. Most state regulatory commissions, including the New Jersey BPU, utilize the accrual methodology set forth in SFAS 87.[10] This is the methodology that is required to be used for financial reporting purposes under Generally Accepted Accounting Principles ("GAAP"). This pronouncement was issued by the Financial Accounting Standards Board ("FASB") in December 1985. This methodology requires a company to accrue pension costs over the working life of the employee.

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

Thus, the calculation of the pension cost is a snapshot at a point in time. It is impacted by what has happened in the past as well as what is expected to happen in the future. In addition, there is a gradual true-up of past estimates with actual results over time. Pursuant to SFAS 87, a pension cost can be either positive or negative. If it is

10 Subsequently codified as Accounting Standards Codification ("ASC") 715.

positive, then the pension plan is under-funded at a given point in time from an actuarial perspective and additional amounts must be accrued. In that case, ratepayers are required to provide for additional recovery of costs in rates. If the pension cost is negative under SFAS 87, then the plan is over-funded at a given point in time, i.e., the accumulated annual accruals exceed the amount required pursuant to SFAS 87, and ratepayers receive a credit in cost of service due to the fact that the pension cost was higher than necessary in prior years. It is important to recognize that the annual pension costs incurred for financial reporting purposes, and used for ratemaking in New Jersey, differ from the calculation of the amount that must be contributed annually to the pension fund. The minimum amount that companies are actually required to fund each year is determined based on the Employee Retirement Income Security Act ("ERISA") and the Pension Protection Act ("PPA"), while IRS regulations cap the amounts of annual funding that are tax deductible. There is often a wide disparity between a company's minimum pension funding requirement and the maximum amount that is tax deductible, providing companies with wide discretion regarding actual pension funding.

Q. What is the Test Year pension expense projected by the Company in its 9 and 3 Update?

A. In its 9 and 3 Update, the Company projected a Test Year negative pension expense for both its electric and gas utilities. Specifically, at Schedule SSJ-30, R-1, the Company projected a negative Test Year pension expense of ($15,960) for its electric utility and of ($14,605) for its gas utility.

Q. Are these the pension expenses that PSE&G included in its revenue requirement claim?

A. No. Instead of including the actual Test Year pension credit, PSE&G included a $0 pension cost in its revenue requirement claim. This has the effect of increasing electric utility rates by $15.960 million and increasing gas rates by $14.605 million.

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

A. Yes, I am recommending that this claim be denied. The Company's proposal to include a $0 pension expense in rates is inconsistent with the determination of pension expense pursuant to FAS 87, which has been used by the Board for many years. The Company states in Mr. Jennings' original testimony that it is entitled to reflect a $0 pension expense, instead of the credit to which ratepayers would otherwise be entitled, due to the fact it has taken steps over the past few years to control pension costs. These include changing eligibility requirements, increasing funding of the pension fund, changes in actuarial assumptions, and adoption of updated accounting standards. However, none of these factors are unusual or suggest that PSE&G has gone beyond its existing fiduciary responsibility –to either its employees, pensioners or its ratepayers.

Q. Please comment on the fact that the Company is entitled to special ratemaking treatment because of the contributions it has made to the pension fund.

A. It is the Company's management that determines the timing and amount of contributions to the pension fund, and the Company has wide discretion each year whether or not to make a contribution to its pension fund. Many factors influence a company's decision with regard to pension funding including tax considerations, the availability of cash, and a company's financial position. Thus, PSE&G's funding decisions are dependent, at least in part, on its ability to manage its earnings and/or to minimize its tax expense. Ratepayers should not be penalized as a result of pension funding decisions made by Company management, especially when those decisions are based on tax avoidance policies or other motives. Rather, utility rates should be based solely on the annual cost of pension benefits approved by the BPU pursuant to FAS 87.

As long as the Board has a policy of using the actuarial method to determine pension expense for ratemaking purposes, then it would be inappropriate to deviate from that methodology simply because PSE&G does not like the result. Therefore, I recommend that the Company's request to include a $0 pension expense in rates be denied. Instead, the annualized cost at June 30, 2018, the end of the Test Year, should be included in the Company's cost of service. At Schedule ACC-17E and ACC-17G, I have made adjustments to reflect this Test Year pension expense in the Company's revenue requirement for the electric and gas utilities respectively.

G. Rate Case Expense

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

A. PSE&G's rate case expense claim is based on total estimated costs for the current case of $1.896 million. The Company has allocated $1.443 million of this amount to the electric utility and $0.453 million to the gas utility. PSE&G is proposing a three-year amortization period for these costs.

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

A. Yes, I am recommending one adjustment. The BPU has a long-standing policy of requiring a 50/50 sharing of rate case costs between shareholders and ratepayers. This policy is based on the assumption that base rate case filings provide benefits to both shareholders and ratepayers, and therefore should be allocated equally between the two groups. The Company has not reflected any sharing of rate case costs in its filing. Accordingly, at Schedules ACC-18E and ACC-18G, I have made adjustments to allocate 50% of the Company's pro forma rate case costs to shareholders. To quantify my adjustment, I accepted the three-year amortization period for rate case costs proposed by PSE&G in its filing. However, if the BPU determines that it is likely that PSE&G will not file another base rate case within the next three years, then a longer amortization period may be appropriate.

H. Storm Damage Expense

Q. How is the Company proposing to treat storm damage costs in this case?

A. The Company is proposing to utilize the deferred storm costs to partially offset the accumulated excess deferred income tax refunds resulting from the TCJA. PSE&G is proposing a similar treatment for certain regulatory assets, as discussed below. The net excess deferred income tax balance, after these offsets, would then be returned to customers through the TAC under the Company's proposal.

Q. What storm damage costs has the Company included in its deferral?

A. The storm damage costs that the Company proposes to recover in this way include three components. First, the Company has included a total of $220.242 million ($212.697 million electric and $7.545 million gas) related to storms in 2010-2012 that the Board reviewed and for which the Board authorized recovery on September 30, 2014 in BPU Docket Nos. AX13030196. Second, the Company has included costs of $20.656 million ($20.636 million electric and $0.020 gas) for additional storms prior to the Test Year. Third, the Company included $24.554 million (all electric) in Test Year storm costs. PSE&G states that if these storm damage costs are not used as an offset to accumulated excess deferred income taxes, then these storm damage costs should be recovered in rates and amortized over a period of 3 years.

Q. Should storm damage costs be used as a partial offset to excess deferred income tax refunds related to the TCJA?

A. No, they should not. I recommend that the BPU deny the Company's request to utilize storm damage costs to offset excess accumulated deferred income taxes. These storm costs are not directly related to the deferred taxes that are being returned to customers. In order to provide the greatest transparency to the ratemaking process, I recommend that the BPU evaluate each component of the revenue requirement individually. In addition, as discussed later in my testimony, I am recommending that the BPU reject the Company's request to establish a TAC. Therefore, I am recommending that both storm damage costs and the refunds related to excess deferred income taxes be included in base distribution rates. Since both storm damage costs and the excess deferred tax refunds are included in my base distribution revenue requirement, the Company's proposal to offset one against the other becomes moot.

Q. Are you recommending any adjustment to the level of storm damage costs for which the Company is seeking recovery?

A. Yes, I recommend that the BPU reject the Company's request to recover storm damage costs that were incurred prior to the Test Year, except for those costs specifically authorized by the BPU Docket No. AX13030196. These interim-period costs were deferred without specific authorization by the Board. Between base rate cases, there are many components of the revenue requirement that vary from the amounts used to set rates in a utility's most recent base rate case. However, it is the Company's shareholders, not its ratepayers, who should bear the risk of these costs variations, just as it is the Company's shareholders, and not ratepayers, that benefit from higher than anticipated earnings. The Company did not request authorization to defer these costs from the Board. Permitting these costs to be recovered in this base rate case, in the absence of prior authorization for deferral, would clearly constitute retroactive ratemaking.

In addition, several of the storm costs incurred during this period were relatively small and are unlikely to have had a material impact on the Company's financial condition. For example, the Company has included three electric utility claims that are each less than $550,000. The Company's entire gas utility claim for storms during this period is only $20,000. Moreover, if the Company believed that any of these storms had a material impact on its financial integrity, it could have filed a request for deferred accounting treatment. It could even have filed a base rate case during this period. Since PSE&G took neither of these actions, it is unreasonable to include these retroactive costs in prospective utility rates. Therefore, I am recommending that the BPU deny the Company's request to recover these interim period costs in regulated distribution rates. Since the Company included these costs in its TAC instead of in its base rate claim, no specific adjustment to my revenue requirement is necessary.

Q. Are you recommending any adjustment to the storm damage costs that were previously authorized by the BPU, or storm damage costs incurred during the Test Year?

A. I am not recommending any adjustment to the amount of such costs, but I recommend that these costs be amortized over 5 years instead of over the 3-period proposed in the Company's alternative ratemaking proposal. These costs were incurred over a period of approximately 8 years, from 2010 through June 30, 2018. In addition, the majority of these costs relate to Superstorm Sandy, an event that was largely unprecedented. Therefore, I believe it is appropriate to recover these costs over a period of at least five years. In Schedules ACC-19E and 19G, I have made an adjustment to include previously-authorized storm damage costs and Test Year storm damage costs in base rates, amortized over a five-year period.

I. <u>Regulatory Asset Amortization Expense</u>

Q. Did the Company also propose that certain regulatory assets be treated in a similar manner to storm damage costs, and offset against excess accumulated deferred income tax refunds, or alternatively be amortized over a period of 3 years?

A. Yes, it did. In its filing, the Company, proposed that costs related to four regulatory assets be offset against the excess accumulated deferred income tax refunds, or alternatively be amortized over a period of three years. Since these costs were deferred by PSE&G, none of these costs were included in the actual Test Year expenses booked by the Company. PSE&G is requesting recovery of the following regulatory assets:

	Electric (000)	Gas (000)
Long Term Capacity Agreement Pilot Program ("LCAPP")	$562	-
Contact Voltage	$46	-
Newark Breaker Project	$669	-
Cape May Street	$928	$10,250
Total	$2,205	$10,250

Q. Did the Company receive prior BPU approval to defer these regulatory assets?

A. The Company received authorization to defer for future recovery the LCAPP costs and the Contact Voltage costs. Deferral and recovery of both of these costs was authorized by the BPU on June 15, 2011, in Docket Nos.EO11010026 and EO10100760. The Company did not receive authorization to recover the costs shown above for the Newark Breaker Project. Finally, the deferral of Cape May Street Project costs is the subject of a separate Petition before the BPU in Docket No. EF17050461.

Q. Are you recommending that any of these regulatory assets be recovered from ratepayers in this case?

A. Yes, I am recommending that the LCAPP costs and the Contact Voltage costs be included in the Company's base distribution revenue requirement and amortized over five years, similar to the recommendation made above for certain storm damage costs. Since I am recommending that the tax refund be rolled into base rates, and since these costs are unrelated to the tax refunds resulting from the TCJA, there is no need, or reason, to offset these regulatory assets against the excess accumulated deferred income tax refunds. Therefore, recovery of the LCAPP costs and the Contact Voltage costs should be handled through base rates. Since these deferred costs are not reflected in the Company's actual Test Year results, it is necessary to make an adjustment to reflect recovery in base rates.

In addition, I am recommending a five-year recovery period for these costs because these costs were authorized for recovery in 2011, over 7 years ago, and have been incurred since that time. Given the period of time over which these costs have been incurred, I believe it is reasonable to utilize a five-year period for recovery. At Schedule ACC-20E, I have made an adjustment to include a five-year amortization of the LCAPP costs and the Contact Voltage costs in base distribution rates, using a five-year amortization period. No adjustment was made to the gas utility, since both of these projects relate solely to the electric utility.

With regard to the Newark Breaker Project, I am recommending that recovery of these costs be denied. While this project was initially included as part of the Energy Strong Program, this project has now been abandoned as discussed on pages 35 and 36 of Mr. Jennings' updated testimony. Therefore, the costs that were incurred related to this project are not needed for the provision of utility service and the associated plant is not used and useful. Therefore, ratepayers should not be required to pay these costs. While the overall Energy Strong Program was authorized by the BPU, the Company retained the obligation to demonstrate that all associated costs recovered from ratepayers were prudently-incurred. In addition, it was the intent of the parties that the plant included in rates pursuant to the Energy Strong Program would be used and useful in the provision of utility service. The Newark Breaker Project clearly does not meet this criteria. Therefore, I recommend that recovery of these costs be denied.

Finally, the Cape May Street Project is the subject of a separate proceeding at this time. It is my understanding that this proceeding has not been consolidated with the base rate case. Therefore, at the present time, issues relating to the Cape May Street Project should be examined in Docket No. EF17050461. Therefore, I have not included costs for either the Newark Breaker Project or the Cape May Street Project in my revenue requirement. Since neither the deferred Newark Breaker Project nor the deferred Cape May Street Project costs were included in the Company's actual Test Year results, no explicit adjustment is necessary.

J. <u>Company Owned Life Insurance ("COLI") Interest Expense</u>

Q. What is COLI?

A. As discussed on pages 26-27 of Mr. Jennings updated testimony, COLI is a corporate-owned investment in cash value life insurance that covers certain Company employees. The Company is the owner and beneficiary of the life insurance. The cash value of the insurance contracts earns a return that has been used by PSE&G to reduce certain benefit costs. In addition, the Company is permitted to borrow against the policy. In this case, PSE&G has included an expense adjustment of $3.173 million for electric and of $0.933 million for gas related to interest expense associated with borrowings under the policies.

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

A. Yes, I am recommending that this interest expense adjustment be disallowed. The Company has not included the COLI policy as a source of capital in its capital structure. Nor has the Company identified the COLI policy as a source of cash working capital available to meet working capital requirements. Therefore, the Company has not identified how it is using the borrowings available under the COLI policy or if these borrowings are being used to benefit ratepayers. Financing for the investment that is being used to provide utility service to electric and gas ratepayers is already provided for in the return and working capital components of the ratemaking equation. Therefore, I recommend that the Company's proposal to recover these interest costs from ratepayers be denied. My adjustment for the electric utility is shown in Schedule ACC-21E and my adjustment for the gas utility is shown in Schedule ACC-20G.

K. <u>Insurance Expense</u>

Q. How did PSE&G determine its claim for insurance expenses in this case?

A. As shown in the workpapers to Exhibit P-2, Schedule SSJ-35, R-1, the Company's Insurance Expense claim is based on the Company's projections for insurance costs in the "Rate Year", which is the twelve-month period beginning in October 2018.

Q. How did the Company determine the projected insurance costs included in its claim?

A. According to the response to RCR-A-128, "The forecasts are developed as part of the annual budget planning process and are based on prior year actual premiums paid escalated (up or down) to account for insurance premium fluctuations in the future (based on estimated market conditions)."

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

A. Yes, I am recommending that speculative increases in insurance premiums be disallowed. As noted in the response to RCR-A-128, the Company's claim is based on estimated premiums and on estimated market conditions, not on known and measurable changes to actual Test Year results. Therefore, I recommend that the Board utilize the actual Test Year insurance costs to determine the Company's revenue requirement in this case. My electric utility adjustment is shown in Schedule ACC-22E and my gas utility adjustment is shown in ACC-21G.

L. <u>Credit Card Fee Expense</u>

Q. Has PSE&G included fees associated with credit card payments in its revenue requirement claim?

A. Yes, it has. PSE&G is proposing to recover fees associated with credit card payments from all ratepayers through its base distribution rates. At the present time, these fees are paid directly by those customers that pay their bills via credit cards.

Q. How did the Company develop its cost claim associated with credit card payments?

A. The Company included estimated Rate Year costs in its revenue requirement, projected for the period October 2018 through September 2019. PSE&G estimated credit card fees of $2.00 per payment. In addition, it projected that usage of credit cards would grow during the Rate Year, from 5.21% of payments in October 2018 to 21.0% of payments in September 2019.

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

A. Yes, I am recommending that the Company's request to include these fees in base rates be denied. Credit card fees should be borne by those ratepayers who choose to use a credit card to pay for their utility service. In many cases, customers choose to utilize credit cards because of points, cash refunds, or other benefits that are directly tied to use of the card. It is unreasonable to ask other ratepayers to subsidize these benefits. Therefore, I am recommending that credit card fees continue to borne by the actual customers that utilize them. I understand that the per-transaction fees currently paid by individual customers (approximately $3.95 per transaction) would be reduced if payment is assumed directly by the utility. Nevertheless, it is unreasonable to pass these costs on to the general body of ratepayers, some of whom may not even have credit cards, especially when it is the individual user of the card who will receive the benefits offered by the credit card. For all these reasons, I am recommending that the Company's proposal to recover the costs of credit card fees from the general body of ratepayers be denied. My adjustment is shown in Schedules ACC-23E and ACC-22G.

Q. If the Board feels that there is merit in allowing the Company to recover credit card fees from the general body of ratepayers, what level of credit card expense should be included in base rates?

A. If, in spite of my recommendation, the Board chooses to permit PSE&G to recover credit card fees from the general body of ratepayers, then it should base its allowance on the percentage of customers using credit cards at the end of the Test Year, approximately 5.2%. Allowing the Company to reflect a greater level of credit card payments in base rates would be speculative and would violate the requirement that post-test year adjustments be known and measurable. Therefore, if the Board permits credit card fees to be recovered in base rates, it should limit these fees to actual credit card payments at the end of the Test Year.

M. Other Compensation – Named Executive Officers ("NEOs")

Q. Are you recommending any adjustments to other compensation provided to the Company's NEOs?

A. Yes, I am recommending that several components of other compensation be disallowed. In the Company's 2018 Proxy Statement, it lists Other Compensation provided by the

Company to executive officers, referred to as NEOs. This other compensation includes such items as automobile expenses, physical examinations, home security systems, personal and spousal travel, personal entertainment, club memberships, and charitable contributions on behalf of officers. These costs should be not borne by regulated ratepayers. Therefore, at Schedules ACC-24E and ACC-23G I have made adjustments to remove these costs from the Company's electric and gas revenue requirements. I did not make any adjustment to exclude the costs associated with 401K payments made by the Company for these individuals, which were also included in the Other Compensation as reported in the Proxy Statement.

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

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

A. Yes, I am. According to the response to RCR-A-89 the Company has included in its filing approximately $1.040 million ($560,000 electric and $480,000 gas) of meals and entertainment expenses that are not deductible on the Company's income tax return. These are costs that the IRS has determined are not appropriate deductions for federal tax purposes. If these costs are not deemed to be reasonable business expenses by the IRS, it seems appropriate to conclude that they are not reasonable business expenses to include in a regulated utility's cost of service. Accordingly, at Schedule ACC-25E and ACC-24G, I have made adjustment to eliminate these costs from the Company's electric and gas revenue requirements.

O. Industry Dues Expense

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

A. Yes, I am. In response to RCR-A-87, the Company indicated that it included $1.345 million (total Company) of industry dues expense in its revenue requirement claims. These dues included payments to such organizations as the New Jersey Utilities Shareholders Association, various Chambers of Commerce, the New Jersey Business and Industry Association and the Edison Electric Institute ("EEI").

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

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

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

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

Similarly, public affairs, media relations, and other advocacy initiatives should not be charged to ratepayers. Accordingly, I am recommending that 20% of the Company's industry dues identified in the response to RCR-A-87 be disallowed on the basis that such costs constitute lobbying activities or should not otherwise be charged to cost of service. I recognize that the specific level of lobbying/public affairs/media activity varies from organization to organization. However, based on my review of these organizations and on recommendations in other utility rate proceedings, I believe that a 20% disallowance is a reasonable overall recommendation. My adjustments are shown in Schedules ACC-26E and ACC-25G.

P. <u>Real Estate Tax Expense</u>

Q. How did the Company determine its Real Estate Tax Expense claim?

A. The Company's claim is based on its projected real estate taxes for the Rate Year starting October 2018. It appears that the Company used its budgeted real estate property tax expense in its revenue requirement.

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

A. Yes, I am recommending that the BPU utilize the annualized June 2018 property tax expense to determine rates in this case. Thus, I have annualized the June 2018 property tax expenses of $1,118,917 for the electric utility and of $428,333 for the gas utility, as shown in the Company's workpapers. The annualized expense is consistent with my recommendation that post-test year plant additions be disallowed. It is also less speculative than the Company's claim, since my recommendation is based on a known and measurable cost at the end of the Test Year. My electric adjustment is shown in Schedule ACC-27E and my gas adjustment is shown in Adjustment ACC-26G.

Q. <u>Depreciation Expense</u>

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

A. Yes, I am recommending three adjustments. First, since I am recommending that post-test year plant additions be excluded from rate base, it is necessary to make a corresponding adjustment to eliminate the associated depreciation expense. At Schedules ACC-28E and 27G, I have made adjustments to eliminate depreciation expense associated with the July- December 2018 plant additions that I recommend be excluded from rate base.

With regard to the Company's claim for new depreciation rates, Rate Counsel witness James Garren is recommending new depreciation rates that result in a significant reduction in depreciation expense from the amount included in the Company's claim. In fact, Mr. Garren is recommending depreciation rates that are lower than the Company's current depreciation rates. Therefore, at Schedule ACC-29E and 28G, I have made adjustments to eliminate the incremental increases in depreciation expenses proposed by PSE&G. In Schedules ACC-30E and 29G, I have made further adjustments to reflect the additional reductions from current depreciation rates recommended by Mr. Garren. Thus, my pro forma depreciation expense is synchronized with Rate Counsel's recommended Test Year plant in-service-balances and with Rate Counsel's proposed depreciation rates.

R. <u>BPU and Rate Counsel Assessments</u>

Q. How did the Company develop its proposed BPU and Rate Counsel assessments in this case?

A. The Company utilized a two-year average to determine its pro forma claim in this case for BPU and Rate Counsel assessments.

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

A. Yes, I am recommending that the Company's proposal to utilize a two-year average of these assessments be denied. Instead, the amount included in rates should include the most recent assessments charged to PSE&G. I am not aware of the BPU utilizing multi-year averages in prior cases to determine pro forma assessment costs in a base rate case. The most recent Test Year information should therefore be included in the Company's revenue requirement. At Schedules ACC-31E and 30G, I have made adjustments to reflect the actual Test Year electric and gas assessments in the Company's revenue requirement. In addition, current assessment rates are included in my recommended revenue multiplier, as discussed below.

S. Interest Synchronization

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

A. Yes, I have made this adjustment at Schedules ACC-32E and ACC-31G. It is consistent (synchronized) with my recommended rate base and with the capital structure and cost of capital recommendations of Mr. Kahal. I am recommending a lower rate base than the rate base included in the Company's filing, which results in a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under Rate Counsel's recommendations. Therefore, I have included an interest synchronization adjustment that reflects a higher pro forma income tax expense for the Company and a decrease to pro forma income at present rates.

T. Income Taxes and Revenue Multiplier

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

A. As shown on Schedules ACC-33E and ACC-32G, I have used a composite income tax factor of 28.11%, which includes a corporate business tax rate of 9.0% and a federal income tax rate of 21%. These are the state and federal income tax rates contained in the

Company's filing.

My revenue multiplier, which is shown in Schedules ACC-34E and ACC-33G, incorporates these tax rates. In addition, the revenue multiplier also includes the BPU and Rate Counsel assessments, based on rates of 0.19% and 0.05% respectively. In addition, the revenue multiplier used for the gas utility also includes uncollectible costs of 1.80%. Uncollectible costs are not included for the electric utility, since uncollectible costs associated with electric service are recovered through the Societal Benefits Charge ("SBC"), and not through base rates. The resulting revenue multipliers that I am recommending are 1.3944 for the electric utility and 1.4200 for the gas utility.

VII. REVENUE REQUIREMENT SUMMARY

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

A. Excluding the tax credits related to the TCJA, which will be discussed later in my testimony, my adjustments indicate a revenue deficiency of $38.402 million for the electric utility (see Schedule ACC-1E) and a revenue deficiency of $32.933 for the gas utility (see Schedule ACC-1G). The overall change to base rates should also include the tax adjustments discussed in the next section of my testimony.

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

A. Yes, at Schedules ACC-35E and ACC-34G, I have quantified the revenue requirement impact of each of the rate of return, rate base, revenue and expense recommendations contained in this testimony.

VIII. TAX CUT AND JOBS ACT OF 2017 REFUNDS

Q. Please summarize the impact of the TCJA on the Company's income tax expense.

A. The TCJA, which became effective January 1, 2018, had a major impact on the cost of service for regulated utilities, including PSE&G. The most significant feature of the TCJA was the reduction in the corporate federal income tax rate from 35% to 21%. This will impact PSE&G's utility rates in two ways. First, the Company's 2018 income tax expense will be reduced, due to the reduction in the corporate income tax rate. In addition, the lower income tax rate will give rise to excess deferred income taxes that must be refunded to customers.

The Company was ordered to prospectively lower its utility rates effective April 1, 2018 to reflect the reduction in the federal income tax rate. In addition, the Company was ordered to refund to customers the difference between utility revenues at the 35% federal income tax rate and pro forma revenues at the lower 21% federal income tax rate for the period January 1, 2018 through March 31, 2018, with interest. I will refer to this three-month period of tax collections as the "stub period".

Q. What are deferred income taxes?

A. Deferred income taxes are taxes that have been collected from ratepayers but have not yet been paid by the Company, due to differences in tax treatment. For example, under the United States Tax Code and IRS regulations, utilities are allowed to depreciate certain assets on an accelerated basis, thus "front loading" depreciation expense in the early years of the asset's useful life for tax purposes. However, for ratemaking purposes, assets are depreciated based on "straight line" depreciation over the asset's full useful life, and the taxes paid by ratepayers in utility rates reflect straight-line depreciation. This results in the collection from ratepayers of higher taxes than the utility is actually paying during the early years of the asset's useful life. The reverse occurs after the asset is fully depreciated for tax purposes. In addition to depreciation expense, there are other expenses that may be handled differently for tax and ratemaking purposes that also result in deferred income taxes. The cumulative amount of taxes that has been collected from ratepayers but has not yet been paid to the IRS is known as accumulated deferred income tax ("ADIT"). In some cases, taxes may be paid prior to being collected from ratepayers, resulting in accumulated deferred income tax assets.

Q. How is ADIT treated for ratemaking purposes?

A.. ADIT is included as an adjustment to rate base. Accumulated deferred taxes that have been collected from ratepayers but not yet paid by the Company are used to reduce rate base, while accumulated deferred taxes that have been paid but not yet collected from ratepayers are rate base additions.

Q. What are excess deferred income taxes?

A. Excess deferred income taxes are the difference between the accumulated deferred income tax liability booked at the prior federal income tax rate of 35% and the accumulated deferred income tax liability at the new federal income tax rate of 21%. PSE&G's current ADIT balance was based on the expectation that the Company's future income would be taxed at the prior federal income tax rate of 35%. Instead, commencing with Calendar Year 2018, the Company's income will be taxed at 21%. The difference represents taxes that were collected from ratepayers but will never be paid, assuming the 21% rate remains in effect.

Q. How are excess deferred income taxes treated for ratemaking purposes?

A. There are two types of excess deferred income taxes – protected and unprotected. Protected excess deferred income taxes relate to deferred taxes associated with plant-related balances, primarily related to accelerated depreciation methodologies (including bonus depreciation) that were permissible for tax purposes, but which were not reflected for ratemaking purposes. Protected excess deferred income taxes are required to be returned to ratepayers using the Average Rate Assumption Method ("ARAM") or an alternate method such as the Reverse South Georgia Method ("RSGM"), which generally provides that the excess deferred taxes cannot be flowed-through to ratepayers more rapidly than the average remaining life of the underlying property that gave rise to the deferred taxes. In order to utilize ARAM, the utility must determine if it has the detailed vintage information available by individual plant assets by book plant account balances within each guideline class. PSE&G has indicated that it does have available the detailed vintage information to allow it to utilize ARAM to determine the appropriate amortization period for returning the protected excess deferred income taxes.

Unprotected excess deferred taxes relate to differences between the tax and ratemaking treatments afforded other types of costs, such as pension and benefit costs, regulatory costs, and costs for which the Company accrues a reserve. Unprotected deferred taxes can be flowed-through for ratemaking purposes over any "reasonable" period.

Q. Please summarize the Company's proposal with regard to issues related to the TCJA.

A. PSE&G is proposing that the BPU establish a new ratemaking mechanism, the TAC, to flow through tax credits associated with the TCJA to ratepayers, and other tax issues. In addition to specific adjustments that the Company is proposing to flow-through the TAC, it is also proposing that the TAC would be used to recover any IRS audit adjustments and to adjust for any future major tax changes in income taxes.

PSE&G initially proposed that the amount of the TAC would change each year, based on variations in the amortization period utilized by PSE&G for excess deferred income taxes. The Company claimed that it should be have the ability to modify the annual amortization of excess deferred income tax refunds in order to mitigate the cash flow impact on the Company during the refund period. PSE&G later modified this proposal in its response to RCR-A-140 and is now proposing a more levelized refund to customers over a five-year period. As shown in the response to RCR-A-140, the Company is now proposing to include the following components in its initial TAC:

- A refund of federal income taxes of $21.789 million for the gas utility and $5.641 million for the electric utility collected during the stub period, which reflects the difference in taxes at the 35% federal income tax rate vs. taxes at the new 21% rate. The Company also proposes to provide interest to ratepayers of approximately $285,000, based on a short-term interest rate. These amounts would be refunded over a period of three months under the Company's latest proposal.
- A refund of net unprotected excess accumulated deferred income taxes over a period of five years. The Company proposes to first net the excess accumulated deferred taxes with deferred storm costs and with certain regulatory assets, and then amortize the net balance over a period of approximately five years.
- A refund of protected excess deferred income taxes, based on the ARAM amortization.
- A charge to ratepayers for the increase to rate base as excess deferred income taxes are amortized to customers.
- Flow-through of the prospective Safe Harbor Adjusted Repair Expense ("SHARE") deduction.

As shown in the response to RCR-A-140, the Company's proposal would result in an initial electric credit of $152.687 million and an initial gas credit of $38.987 for the first twelve months after the effective date of new rates. Annual rate credits after the first year would be approximately $121.587 million for the electric utility and of $30.808 million for the gas utility.

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

A. Yes, I am recommending several adjustments. First, I am recommending that the Company's request to establish a separate TAC mechanism be denied. Income taxes are an integral part of the ratemaking process and there is no reason why these income tax components should be handled in a separate clause mechanism. Over the past few years, the use of clause mechanisms or other special ratemaking mechanisms has exploded at PSE&G. These mechanisms all have one common element – they shift risk from the Company's shareholders to its ratepayers. I recommend that the BPU oppose the Company's request to continue this trend with the establishment of another rider surcharge. Moreover, while the Company claims that the TAC would initially be utilized to flow through tax credits to ratepayers, PSE&G acknowledges that it is also its intent to use the TAC to recognize the impacts of tax audits or other tax changes, which could result in additional charges to New Jersey ratepayers. Therefore, I recommend that the TAC be rejected, and instead that all tax adjustments be reflected in base distribution rates.

Second, I recommend that the refund associated with the January through March, 2018 excess tax collection be returned to customers as a one-time credit. Moreover, these amounts should be returned to customers within 60 days after the issuance of a final Order in this case, unless the Board orders an earlier refund. In addition, these stub period costs should be refunded with interest, based on the short-term interest rate proposed by PSE&G.

Third, I am recommending that unprotected excess deferred income taxes be returned to customers over a period of five years. As previously discussed earlier in my testimony, I am opposed to the Company's proposal to offset these costs with deferred storm damage costs and other regulatory assets. Moreover, since I am recommending that excess deferred income tax refunds be included in base rates, the Company's proposal to offset these refunds with storm damage costs and other regulatory assets is effectively moot.

I am not recommending any adjustment to the Company's proposals with regard to protected excess deferred income taxes. Nor am I recommending any adjustment to the Company's proposal to flow through the prospective SHARE allowance. I am, however, recommending that the Company's claim to recover additional return on investment as these amounts are refunded to customers be denied.

Q. What is the basis for your recommendation to eliminate the additional return on rate base being requested by PSE&G?

A. Between base rate filings, there are numerous factors that impact upon rate base, and therefore impact the return realized by the Company. Nevertheless, rate base has not traditionally been trued-up between base rate case filings. There is no reason to adjust base rates for changes in rate base related to reductions in excess deferred income taxes, especially as additional deferred taxes will no doubt be added to rate base as plant additions are placed into service. Moreover, there are many factors that will impact upon the Company's earnings between base rate filings. The Company's shareholders rightfully bear the risk of earnings shortfalls between base rate case filings, and in turn shareholders benefit from any excess earnings between base rate case filings. This is the nature of the traditional ratemaking process. Therefore, I have not included the Company's proposed incremental return on rate base in my revenue requirement calculation.

Q. Please quantify the income tax refunds that you have included in your revenue requirement recommendation.

A. As shown in Schedule ACC-Tax, I am recommending that the BPU adjust base rates to reflect tax refunds of $87.270 million for the electric utility and of $139.676 million for the gas utility. This recommendation is based on the following refunds:

- a refund of unprotected excess deferred federal income taxes over five years,

- a refund of protected excess deferred federal income taxes, based on ARAM, and
- inclusion of the prospective SHARE deduction.

In addition, the Company should be ordered to flow through the stub period refund of $5.641 million for the electric utility and of $21.789 million for the gas utility within 60 days of the final Order being issued in this case.

Q. Are there additional tax refunds that are due to ratepayers in future years?

A. Yes, there are. In addition to the refund of excess deferred income taxes and the current SHARE deductions discussed above, there are also prior SHARE deductions that the Company has not yet flowed through to ratepayers. PSE&G is proposing that these tax benefits be flowed through to customers beginning in approximately five years, after the excess deferred income taxes have been returned to New Jersey ratepayers. I have not reflected any adjustments to the Company's proposal relating to these prior SHARE deductions

Q. What is the impact of the tax adjustments that you are proposing?

A. As shown in Schedule ACC-Tax, I am proposing that base distribution rates reflect a tax refund of $87.270 million for the electric utility and of $139.676 million relating to the gas utility.

IX. RATE COUNSEL REVENUE REQUIREMENT SUMMARY

Q. Please summarize the overall revenue requirement recommendations in this case.

A. I am recommending that the BPU authorize a base rate revenue decrease for the electric utility of $48.868 million and a base rate revenue decrease for the gas utility of $106.743 million. This recommendation includes the following:

	Electric (000)	Gas (000)
Base Rate Revenue Change Excluding Tax Refunds	$38,402	$32,933
Base Rate Revenue Change Relating to Tax Refunds	($87,270)	($139,676)
Total Base Rate Change	($48,868)	($106,743)

In addition, the Company should be ordered to flow through the stub period refund of $5.641 million for the electric utility and of $21.789 million for the gas utility within 60 days of an Order in this case.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

List of Testimonies Filed Since January 2008

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Public Service Electric and Gas Co.	E/G	New Jersey	ER18010029/ GR18010030	8/18	Revenue Requirements	Division of Rate Counsel
Westar Energy, Inc.	E	Kansas	18-WSEE-328-RTS	6/18	Revenue Requirements	Citizens' Utility Ratepayer Board
Southwestern Public Service Company	E	New Mexico	17-00255-UT	4/18	Revenue Requirements	Office of Attorney General
Empire District Electric Company	E	Kansas	18-EPDE-184-PRE	3/18	Approval of Wind Generation Facilities	Citizens' Utility Ratepayer Board
GPE/ Kansas City Power & Light Co., Westar Energy, Inc.	E	Kansas	18-KCPE-095-MER	1/18	Proposed Merger	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Co.	E	New Jersey	GR17070776	1/18	Gas System Modernization Program	Division of Rate Counsel
Southwestern Public Service Company	E	New Mexico	17-00044-UT	10/17	Approval of Wind Generation Facilities	Office of Attorney General
Kansas Gas Service	G	Kansas	17-KGSG-455-ACT	9/17	MGP Remediation Costs	Citizens' Utility Ratepayer Board
Atlantic City Electric Company	E	New Jersey	ER17030308	8/17	Base Rate Case	Division of Rate Counsel
Public Service Company of New Mexico	E	New Mexico	16-00276-UT	6/17	Testimony in Support of Stipulation	Office of Attorney General
Westar Energy, Inc.	E	Kansas	17-WSEE-147-RTS	5/17	Abbreviated Rate Case	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	17-KCPE-201-RTS	4/17	Abbreviated Rate Case	Citizens' Utility Ratepayer Board
GPE/ Kansas City Power & Light Co., Westar Energy, Inc.	E	Kansas	16-KCPE-593-ACQ	12/16	Proposed Merger	Citizens' Utility Ratepayer Board
Kansas Gas Service	G	Kansas	16-KGSG-491-RTS	9/16	Revenue Requirements	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	15-00312-UT	7/16	Automated Metering Infrastructure	Office of Attorney General
Kansas City Power and Light Company	E	Kansas	16-KCPE-160-MIS	6/16	Clean Charge Network	Citizens' Utility Ratepayer Board
Kentucky American Water Company	W	Kentucky	2016-00418	5/16	Revenue Requirements	Attorney General/LFUCG
Black Hills/Kansas Gas Utility Company	G	Kansas	16-BHCG-171-TAR	3/16	Long-Term Hedge Contract	Citizens' Utility Ratepayer Board
General Investigation Regarding Accelerated Pipeline Replacement	G	Kansas	15-GIMG-343-GIG	1/16	Cost Recovery Issues	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	15-00261-UT	1/16	Revenue Requirements	Office of Attorney General
Atmos Energy Company	G	Kansas	16-ATMG-079-RTS	12/15	Revenue Requirements	Citizens' Utility Ratepayer Board
El Paso Electric Company	E	New Mexico	15-00109-UT	12/15	Sale of Generating Facility	Office of Attorney General
El Paso Electric Company	E	New Mexico	15-00127-UT	9/15	Revenue Requirements	Office of Attorney General
Rockland Electric Company	E	New Jersey	ER14030250	9/15	Storm Hardening Surcharge	Division of Rate Counsel
El Paso Electric Company	E	New Mexico	15-00099-UT	8/15	Certificate of Public Convenience - Ft. Bliss	Office of Attorney General

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Southwestern Public Service Company	E	New Mexico	15-00083-UT	7/15	Approval of Purchased Power Agreements	Office of Attorney General
Westar Energy, Inc.	E	Kansas	15-WSEE-115-RTS	7/15	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	15-KCPE-116-RTS	5/15	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast Cable Communications	C	New Jersey	CR14101099-1120	4/15	Cable Rates (Form 1240)	Division of Rate Counsel
Liberty Utilities (Pine Buff Water)	W	Arkansas	14-020-U	1/15	Revenue Requirements	Office of Attorney General
Public Service Electric and Gas Co.	E/G	New Jersey	EO14080897	11/14	Energy Efficiency Program Extension II	Division of Rate Counsel
Exelon and Pepco Holdings, Inc.	E	New Jersey	EM14060581	11/14	Synergy Savings, Customer Investment Fund, CTA	Division of Rate Counsel
Black Hills/Kansas Gas Utility Company	G	Kansas	14-BHCG-502-RTS	9/14	Revenue Requirements	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	14-00158-UT	9/14	Renewable Energy Rider	Office of Attorney General
Public Service Company of New Mexico	E	New Mexico	13-00390-UT	8/14	Abandonment of San Juan Units 2 and 3	Office of Attorney General
Atmos Energy Company	G	Kansas	14-ATMG-320-RTS	5/14	Revenue Requirements	Citizens' Utility Ratepayer Board
Rockland Electric Company	E	New Jersey	ER13111135	5/14	Revenue Requirements	Division of Rate Counsel
Kansas City Power and Light Company	E	Kansas	14-KCPE-272-RTS	4/14	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Comcast Cable Communications	C	New Jersey	CR13100885-906	3/14	Cable Rates	Division of Rate Counsel
New Mexico Gas Company	G	New Mexico	13-00231-UT	2/14	Merger Policy	Office of Attorney General
Water Service Corporation (Kentucky)	W	Kentucky	2013-00237	2/14	Revenue Requirements	Office of Attorney General
Oneok, Inc. and Kansas Gas Service	G	Kansas	14-KGSG-100-MIS	12/13	Plan of Reorganization	Citizens' Utility Ratepayer Board
Public Service Electric & Gas Company	E/G	New Jersey	EO13020155 GO13020156	10/13	Energy Strong Program	Division of Rate Counsel
Southwestern Public Service Company	E	New Mexico	12-00350-UT	8/13	Cost of Capital, RPS Rider, Gain on Sale, Allocations	New Mexico Office of Attorney General
Westar Energy, Inc.	E	Kansas	13-WSEE-629-RTS	8/13	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	13-115	8/13	Revenue Requirements	Division of the Public Advocate
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	13-MKEE-447-MIS	8/13	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Jersey Central Power & Light Company	E	New Jersey	ER12111052	6/13	Reliability Cost Recovery Consolidated Income Taxes	Division of Rate Counsel
Mid-Kansas Electric Company	E	Kansas	13-MKEE-447-MIS	5/13	Transfer of Certificate Regulatory Policy	Citizens' Utility Ratepayer Board
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	13-MKEE-452-MIS	5/13	Formula Rates	Citizens' Utility Ratepayer Board

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Chesapeake Utilities Corporation	G	Delaware	12-450F	3/13	Gas Sales Rates	Attorney General
Public Service Electric and Gas Co.	E	New Jersey	EO12080721	1/13	Solar 4 All - Extension Program	Division of Rate Counsel
Public Service Electric and Gas Co.	E	New Jersey	EO12080726	1/13	Solar Loan III Program	Division of Rate Counsel
Lane Scott Electric Cooperative	E	Kansas	12-MKEE-410-RTS	11/12	Acquisition Premium, Policy Issues	Citizens' Utility Ratepayer Board
Kansas Gas Service	G	Kansas	12-KGSG-835-RTS	9/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	12-KCPE-764-RTS	8/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Woonsocket Water Division	W	Rhode Island	4320	7/12	Revenue Requirements	Division of Public Utilities and Carriers
Atmos Energy Company	G	Kansas	12-ATMG-564-RTS	6/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	110258	5/12	Cost of Capital	Division of the Public Advocate
Mid-Kansas Electric Company (Western)	E	Kansas	12-MKEE-491-RTS	5/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Atlantic City Electric Company	E	New Jersey	ER11080469	4/12	Revenue Requirements	Division of Rate Counsel
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	12-MKEE-380-RTS	4/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	11-381F	2/12	Gas Cost Rates	Division of the Public Advocate
Atlantic City Electric Company	E	New Jersey	EO11110650	2/12	Infrastructure Investment Program (IIP-2)	Division of Rate Counsel
Chesapeake Utilities Corporation	G	Delaware	11-384F	2/12	Gas Service Rates	Division of the Public Advocate
New Jersey American Water Co.	W/WW	New Jersey	WR11070460	1/12	Consolidated Income Taxes Cash Working Capital	Division of Rate Counsel
Westar Energy, Inc.	E	Kansas	12-WSEE-112-RTS	1/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Puget Sound Energy, Inc.	E/G	Washington	UE-111048 UG-111049	12/11	Conservation Incentive Program and Others	Public Counsel
Puget Sound Energy, Inc.	G	Washington	UG-110723	10/11	Pipeline Replacement Tracker	Public Counsel
Empire District Electric Company	E	Kansas	11-EPDE-856-RTS	10/11	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast Cable	C	New Jersey	CR11030116-117	9/11	Forms 1240 and 1205	Division of Rate Counsel
Artesian Water Company	W	Delaware	11-207	9/11	Revenue Requirements Cost of Capital	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	10-KCPE-415-RTS (Remand)	7/11	Rate Case Costs	Citizens' Utility Ratepayer Board
Midwest Energy, Inc.	G	Kansas	11-MDWE-609-RTS	7/11	Revenue Requirements	Citizens' Utility Ratepayer Board

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Kansas City Power & Light Company	E	Kansas	11-KCPE-581-PRE	6/11	Pre-Determination of Ratemaking Principles	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	10-421	5/11	Revenue Requirements Cost of Capital	Division of the Public Advocate
Mid-Kansas Electric Company	E	Kansas	11-MKEE-439-RTS	4/11	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
South Jersey Gas Company	G	New Jersey	GR10060378-79	3/11	BGSS / CIP	Division of Rate Counsel
Chesapeake Utilities Corporation	G	Delaware	10-296F	3/11	Gas Service Rates	Division of the Public Advocate
Westar Energy, Inc.	E	Kansas	11-WSEE-377-PRE	2/11	Pre-Determination of Wind Investment	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	10-295F	2/11	Gas Cost Rates	Attorney General
Delmarva Power and Light Company	G	Delaware	10-237	10/10	Revenue Requirements Cost of Capital	Division of the Public Advocate
Pawtucket Water Supply Board	W	Rhode Island	4171	7/10	Revenue Requirements	Division of Public Utilities and Carriers
New Jersey Natural Gas Company	G	New Jersey	GR10030225	7/10	RGGI Programs and Cost Recovery	Division of Rate Counsel
Kansas City Power & Light Company	E	Kansas	10-KCPE-415-RTS	6/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Atmos Energy Corp.	G	Kansas	10-ATMG-495-RTS	6/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Empire District Electric Company	E	Kansas	10-EPDE-314-RTS	3/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	09-414 and 09-276T	2/10	Cost of Capital Rate Design Policy Issues	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	09-385F	2/10	Gas Cost Rates	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	09-398F	1/10	Gas Service Rates	Division of the Public Advocate
Public Service Electric and Gas Company	E	New Jersey	ER09020113	11/09	Societal Benefit Charge Non-Utility Generation Charge	Division of Rate Counsel
Delmarva Power and Light Company	G	Delaware	09-277T	11/09	Rate Design	Division of the Public Advocate
Public Service Electric and Gas Company	E/G	New Jersey	GR09050422	11/09	Revenue Requirements	Division of Rate Counsel
Mid-Kansas Electric Company	E	Kansas	09-MKEE-969-RTS	10/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Westar Energy, Inc.	E	Kansas	09-WSEE-925-RTS	9/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08050326 EO08080542	8/09	Demand Response Programs	Division of Rate Counsel
Public Service Electric and Gas Company	E	New Jersey	EO09030249	7/09	Solar Loan II Program	Division of Rate Counsel

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Midwest Energy, Inc.	E	Kansas	09-MDWE-792-RTS	7/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Westar Energy and KG&E	E	Kansas	09-WSEE-641-GIE	6/09	Rate Consolidation	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	09-60	6/09	Cost of Capital	Division of the Public Advocate
Rockland Electric Company	E	New Jersey	GO09020097	6/09	SREC-Based Financing Program	Division of Rate Counsel
Tidewater Utilities, Inc.	W	Delaware	09-29	6/09	Revenue Requirements Cost of Capital	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	08-269F	3/09	Gas Service Rates	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	08-266F	2/09	Gas Cost Rates	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	09-KCPE-246-RTS	2/09	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08090840	1/09	Solar Financing Program	Division of Rate Counsel
Atlantic City Electric Company	E	New Jersey	EO06100744 EO08100875	1/09	Solar Financing Program	Division of Rate Counsel
West Virginia-American Water Company	W	West Virginia	08-0900-W-42T	11/08	Revenue Requirements	The Consumer Advocate Division of the PSC
Westar Energy, Inc.	E	Kansas	08-WSEE-1041-RTS	9/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Artesian Water Company	W	Delaware	08-96	9/08	Cost of Capital, Revenue, New Headquarters	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR08020113	9/08	Form 1205 Equipment & Installation Rates	Division of Rate Counsel
Pawtucket Water Supply Board	W	Rhode Island	3945	7/08	Revenue Requirements	Division of Public Utilities and Carriers
New Jersey American Water Co.	W/WW	New Jersey	WR08010020	7/08	Consolidated Income Taxes	Division of Rate Counsel
New Jersey Natural Gas Company	G	New Jersey	GR07110889	5/08	Revenue Requirements	Division of Rate Counsel
Kansas Electric Power Cooperative, Inc.	E	Kansas	08-KEPE-597-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Company	E	New Jersey	EX02060363 EA02060366	5/08	Deferred Balances Audit	Division of Rate Counsel
Cablevision Systems Corporation	C	New Jersey	CR07110894, et al..	5/08	Forms 1240 and 1205	Division of Rate Counsel
Midwest Energy, Inc.	E	Kansas	08-MDWE-594-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	07-246F	4/08	Gas Service Rates	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR07100717-946	3/08	Form 1240	Division of Rate Counsel
Generic Commission Investigation	G	New Mexico	07-00340-UT	3/08	Weather Normalization	New Mexico Office of Attorney General
Southwestern Public Service Company	E	New Mexico	07-00319-UT	3/08	Revenue Requirements Cost of Capital	New Mexico Office of Attorney General

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Delmarva Power and Light Company	G	Delaware	07-239F	2/08	Gas Cost Rates	Division of the Public Advocate
Atmos Energy Corp.	G	Kansas	08-ATMG-280-RTS	1/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board

APPENDIX B

Supporting Schedules

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
TEST YEAR ENDING JUNE 30, 2018
TAX ADJUSTMENTS ($000)

	Electric	Gas
	(A)	(A)
1. Unprotected Excess Per Company	$228,749	$270,357
3. Amortization Period	5	5
4. Annual Amortization	$45,750	$54,071
5. Annual Amortization - Protected EDIT	10,560	6,900
6. Flow Through of SHARE	6,276	37,392
7. Total	$62,586	$98,363
8. Tax Gross-Up	1.3944	1.4200
9. Annual Impact - Reduction	**$87,270**	**$139,676**

Sources:
(A) Response to RCR-A-140.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REVENUE REQUIREMENT SUMMARY ($000)

	Company Claim	Recommended Adjustment	Recommended Position	
	(A)			
1. Pro Forma Rate Base	$5,672,133	($207,399)	$5,464,734	(B)
2. Required Cost of Capital	7.39%	-0.77%	6.62%	(C)
3. Required Return	$419,171	($57,163)	$362,008	
4. Operating Income @ Present Rates	275,892	58,576	334,468	(D)
5. Operating Income Deficiency	$143,279	($115,739)	$27,540	
6. Revenue Multiplier	1.3944	1.3944	1.3944	(E)
7. Revenue Increase Excl. Tax Adj.	$199,788	($161,387)	$38,402	
8. Roll in of Tax Refunds			($87,270)	(F)
9. Total Base Rate Reduction			**($48,868)**	

Sources:
(A) Company Filing, Schedule P-2, Schedule SSJ-2, R-1.
(B) Schedule ACC-2E.
(C) Schedule ACC-3E.
(D) Schedule ACC-11E.
(E) Schedule ACC-34E.
(F) Schedule ACC-Tax.

Schedule ACC-2E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REQUIRED COST OF CAPITAL ($ MILLIONS)

	Capital Structure (%	Cost Rate (%)	Weighted Cost (%)
	(A)	(A)	
1. Long Term Debt	46.36%	3.96%	1.84%
2. Customer Deposits	0.48%	0.87%	0.00%
3. Common Equity	53.16%	9.00%	4.78%
4. Total Cost of Capital	100.00%		**6.62%**

Sources:
(A) Testimony of Mr. Kahal, Schedule MIK-1, page 1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
RATE BASE SUMMARY ($000)

	Company Claim (A)	Recommended Adjustment		Recommended Position
1. Utility Plant in Service	$9,501,367	($133,787)	(B)	$9,367,580
2. Plant Held for Future Use	495	(495)	(C)	$0
Less:				
3. Accumulated Depreciation	(2,667,560)	126,486	(D)	(2,541,074)
4. Advances for Construction	(26,354)	0		(26,354)
5. Net Utility Plant	$6,807,948	($7,796)		$6,800,152
Plus:				
6. Cash Working Capital	$404,990	($206,849)	(E)	$198,141
7. Materials and Supplies	107,301	0		107,301
8. Prepayments	999	0		999
Less:				
9. Customer Deposits	$0	$0		$0
10. Accumulated Deferred Taxes	(1,648,550)	19,684	(F)	(1,628,866)
11. Consolidated Income Taxes	(555)	(12,438)	(G)	(12,993)
12. Total Rate Base	**$5,672,133**	**($207,399)**		**$5,464,734**

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-3, R-1.
(B) Schedule ACC-4E and Schedule ACC-5E.
(C) Schedule ACC-6E.
(D) Schedule ACC-7E.
(E) Schedule ACC-8E.
(F) Schedule ACC-9E.
(G) Schedule ACC-10E.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
UTILITY PLANT IN SERVICE - POST TEST YEAR ($000)

1.	Test Year Ending Balance	$9,367,658	(A)
2.	Company Claimed Plant	9,501,367	(A)
3.	Recommended Adjustment	**($133,709)**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-7, R-1.

Schedule ACC-5E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
UTILITY PLANT IN SERVICE - TRAKSMART ($000)

1.	Amount Included in Rate Base	$78	(A)
2.	Recommended Adjustment	**($78)**	

Sources:
(A) Per Company at informal discovery conference, 6/29/18.

Schedule ACC-6E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
PLANT HELD FOR FUTURE USE ($000)

1.	Company Claim	$495	(A)
2.	Recommended Adjustment	**($495)**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-3, R-1.

Schedule ACC-7E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
ACCUMULATED DEPRECIATION-POST TEST YEAR ($000)

1.	Test Year Ending Balance	($2,541,074)	(A)
2.	Company Claim	(2,667,560)	(A)
3.	Recommended Adjustment	**$126,486**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-9, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
CASH WORKING CAPITAL ($000)

1.	Recommended Cash Working Capital	$198,141	(A)
2.	Company Claim (Lead/Lag Study)	404,990	(B)
3.	Recommended Adjustment	**($206,849)**	

Sources:
(A) Reflects Rate Counsel adjustments. See Crane CWC Workpaper.
(B) Company Filing, Exhibit P-8, R-1, Schedule HW-1, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
DEFERRED INCOME TAX RESERVE ($000)

1.	Test Year Ending Balance	($1,628,866)	(A)
2.	Company Claim	(1,648,550)	(A)
3.	Recommended Adjustment	**$19,684**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-13, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
CONSOLIDATED INCOME TAXES ($000)

1. Sum of Net Taxable Losses for Companies With Cumulative Taxable Losses	($150,997)	(A)
2. Tax Loss Benefit Based on Annual Federal Income Tax Rate	(52,849)	(A)
3. Share of PSE&G-Electric Cumulative Positive Taxable Income to Total for Companies With Cumulative Taxable Income	31.52%	(A)
4. Total CIT Adjustment for PSE&G	($16,658)	
5. Electric Percentage	78.00%	
6. Electric Adjustment	**($12,993)**	

Sources:
(A) Reflects Rate Counsel adjustments to Exhbiit P-4, R-1, Schedule RCK-6A, R-1.
See Crane CTA Workpaper.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
OPERATING INCOME SUMMARY ($000)

			Schedule
1.	Company Claim	$275,892	
	Recommended Adjustments:		
2.	Pro Forma Revenue - Weather Normalization	(416)	12E
3.	Salary and Wage Expense	594	13E
4.	Incentive Compensation Program Expense	8,538	14E
5.	Payroll Tax Expense	635	15E
6.	Fringe Benefits	936	16E
7.	Pension Expense	11,474	17E
8.	Rate Case Expense	173	18E
9.	Storm Damage Expense	(34,112)	19E
10.	Regulatory Asset Amortization Expense	(87)	20E
11.	COLI Interest Expense	3,173	21E
12.	Insurance Expense	87	22E
13.	Credit Card Fee Expense	3,041	23E
14.	Other Compensation Expense - NEOs	45	24E
15.	Meals and Entertainment Expense	403	25E
16.	Industry Dues Expense	89	26E
17.	Real Estate Tax Expense	383	27E
18.	Depreciation Expense - Plant-in-Service	3,004	28E
19.	Depreciation Expense - New Rates	41,210	29E
20.	Depreciation Expense - Rate Counsel Rates	19,683	30E
21.	BPU and Rate Counsel Assessments	742	31E
22.	Interest Synchronization	(1,018)	32E
23.	Operating Income	**$334,468**	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
PRO FORMA REVENUES - WEATHER NORMALIZATION ($000)

1.	Weather Normalization Adjustment - 30 Year Normal		$5,260	(A)
2.	Weather Normalization Adjustment Per Company		5,840	(B)
3.	Recommended Adjustment		$580	
4.	Revenue Assessments @	0.25%	1	(C)
5.	Net Revenue Adjustment		$579	
6.	Income Taxes @	28.11%	163	
7.	Operating Income Reduction		**$416**	

Sources:
(A) Response to RCR-A-127.
(B) Company Filing, Exhibit P-2, Schedule SSJ-32, R-1.
(C) Assessment rates per Schedule ACC-34E.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
SALARY AND WAGE EXPENSE ($000)

1.	Company Claim		$4,379	(A)
2.	Rate Counsel Recommendation		3,553	(B)
3.	Recommended Adjustment		$826	
4.	Income Taxes @	28.11%	232	
5.	Operating Income Impact		**$594**	

Sources:
(A) Company Exhibit P-2, Schedule SSJ-27, R-1.
(B) Reflects annualization of first nine months of Test Year and elimination of 2019 increases. See Crane Salary Workpapers.

Schedule ACC-14E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INCENTIVE COMPENSATION PROGRAM EXPENSE ($000)

1.	Employee Incentive Compensation		$13,290	(A)
2.	Recommended Adjustment (%)		50.00%	(B)
3.	Recommended Adjustment ($)		$6,645	
4.	Officer Incentive Compensation		5,232	(C)
5.	Total Recommended Adjustment		$11,877	
6.	Income Taxes @	28.11%	3,339	
7.	Operating Income Impact		**$8,538**	

Sources:
(A) Average of 2016 and 2017 Expense per the reponse to RCR-A-141.
(B) Recommendation of Ms. Crane.
(C) Response to RCR-A-142.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
PAYROLL TAX EXPENSE ($000)

1.	Salary and Wage Adjustment		$826	(A)
2.	Incentive Compensation Adjustment		11,877	(B)
3.	Total Recommended Adjustments		$12,703	
4.	Tax Rate Per Company		6.95%	(C)
5.	Recommended Payroll Tax Adjustment		$883	
6.	Income Taxes @	28.11%	248	
7.	Operating Income Impact		**$635**	

Sources:
(A) Schedule ACC-13E.
(B) Schedule ACC-14E.
(C) Payroll Tax Workpapers per Company.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
FRINGE BENEFITS EXPENSE

1	Test Year Fringe Benefit Cost Excluding Pension		$50,208	(A)
2.	Company Claim		51,510	(A)
3.	Recommended Adjustment		$1,302	
4.	Income Taxes @	28.11%	366	
5.	Operating Income Impact		**$936**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-30, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
PENSION EXPENSE ($000)

1. Test Year Pension Cost		($15,960)	(A)
2. Company Claim		0	(A)
3. Recommended Adjustment		$15,960	
4. Income Taxes @	28.11%	4,486	
5. Operating Income Impact		**$11,474**	

Sources:
(A) Exhibit P-2, Schedule SSJ-30, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
RATE CASE EXPENSE ($000)

1. Company Claim		$1,443	(A)
2. Recommended Amortization Period		3	(B)
3. Annual Amortization		$481	
4. Allocation to Ratepayers (%)		50.00%	(C)
5. Allocation to Ratepayers ($)		$241	
6. Company Claim - Annual Expense		481	
7. Recommended Adjustment		$241	
8. Income Taxes @	28.11%	68	
9. Operating Income Impact		**$173**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-44, R-1.
(B) Recommendation of Ms. Crane.
(C) Reflects BPU Policy of 50/50 sharing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
STORM DAMAGE EXPENSE ($000)

1.	2010-2012 Deferred Storm Costs		$212,697	(A)
2.	Test Year Deferred Storm Costs		24,554	(B)
3.	Total Amount to be Amortized		$237,251	
4.	Proposed Amortization Period		5	(C)
5.	Annual Amortization		$47,450	
6.	Income Taxes @	28.11%	13,338	
7.	Operating Income Reduction		**$34,112**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-39, R-1.
(B) Company Filing, Exhibit P-2, Schedule SSJ-40, R-1.
(C) Recommendation of Ms. Crane.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REGULATORY ASSET AMORTIZATION EXPENSE ($000)

1. Long Term Capacity Agreement Pilot Program		$562	(A)
2. Contract Voltage		46	(A)
3. Total Amount to be Amortized		$608	
4. Proposed Amortization Period		5	(B)
5. Annual Amortization		$122	
6. Income Taxes @	28.11%	34	
7. Operating Income Reduction		**$87**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-43, R-1.
(B) Recommendation of Ms. Crane.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
COLI INTEREST EXPENSE ($000)

1.	Company Claim	$3,173	(A)
2.	Operating Income Impact	**$3,173**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-31, R-1.

Schedule ACC-22E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INSURANCE EXPENSE ($000)

1	Test Year Insurance Costs		$3,904	(A)
2.	Company Claim		4,025	(A)
3.	Recommended Adjustment		$121	
4.	Income Taxes @	28.11%	34	
5.	Operating Income Impact		**$87**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-35, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
CREDIT CARD FEE EXPENSE ($000)

1.	Recommended Adjustment		$4,230	(A)
2.	Income Taxes @	28.11%	1,189	
3.	Operating Income Impact		**$3,041**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-45, R-1

Schedule ACC-24E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
OTHER COMPENSATION EXPENSE - NEOs ($000)

1.	Total Other Compensation - NEOs		$381	(A)
2.	Less 401K Match		65	(B)
3.	Recommended Adjustment		$316	
4.	Allocation to Electric (%)		20.0%	(C)
5.	Recommended Electric Adjustment		$63	
6.	Income Taxes @	28.11%	18	
7.	Operating Income Impact		**$45**	

Souces:

(A) 2018 Proxy Statement, page 66.
(B) 2018 Proxy Statement, page 67.
(C) Per Company, informal discovery on June 29, 2018.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
MEALS AND ENTERTAINMENT EXPENSE ($000)

1.	Recommended Adjustment		$560	(A)
2.	Income Taxes @	28.11%	157	
3.	Operating Income Impact		**$403**	

Sources:
(A) Response to RCR-A-89.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INDUSTRY DUES EXPENSE ($000)

1.	Company Claim		$617	(A)
2.	Recommended Adjustment (%)		20.00%	(B)
3.	Recommended Adjustment ($)		$123	
4.	Income Taxes @	28.11%	35	
5.	Operating Income Impact		**$89**	

Sources:
(A) Response to RCR-A-87.
(B) Recommendation of Ms. Crane.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REAL ESTATE TAX EXPENSE ($000)

1. Annualized Cost @ June 30, 2018		$13,427	(A)
2. Company Claim		13,960	(B)
3. Total Recommended Tax Adjustment		$533	
4. Income Taxes @	28.11%	150	
5. Recommended Adjustment		**$383**	

Sources:
(A) Based on annualizing June 2018 expense per Company workpaper.
(B) Company Filing, Exhibit P-2, Schedule SSJ-34, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
DEPRECIATION EXPENSE - PLANT-IN-SERVICE ($000)

1.	Annualized Depreciation @ June 30, 2018		$244,685	(A)
2.	Annualized Depreciation @ Dec. 31, 2018		248,863	(A)
3.	Recommended Adjustment		$4,178	
4.	Income Taxes @	28.11%	1,174	
5.	Operating Income Impact		**$3,004**	

Sources:
(A) Workpaper to Exhibit P-2, Schedule SSJ-38, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
DEPRECIATION EXPENSE - NEW RATES ($000)

1. Annualized Depreciation @ 12/31/18 - New Rates		$306,187	(A)
2. Annualized Depreciation @ 12/31/18 - Old Rates		248,863	(A)
3. Recommended Adjustment		$57,324	
4. Income Taxes @	28.11%	16,114	
5. Operating Income Impact		**$41,210**	

Sources:
(A) Workpaper to Company Filing, Exhibit P-2, Schedule SSJ-38, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
DEPRECIATION EXPENSE - RATE COUNSEL RATES ($000)

1.	Annualized Depreciation @ June 30, 2018 Per Company		$244,685	(A)
2.	Annualized Depreciation @ June 30, 2018 Per Rate Counsel		217,306	(B)
3.	Recommended Adjustment		$27,379	
4.	Income Taxes @	28.11%	7,696	
5.	Operating Income Impact		**$19,683**	

Sources:
(A) Workpaper to Company Filing, Exhibit P-2, Schedule SSJ-38, R-1.
(B) Depreciation Workpaper of Mr. Garren.

Schedule ACC-31E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
BPU AND RATE COUNSEL ASSESSMENTS ($000)

		(A)	
1. 2018 BPU Assessment		$8,655	
2. Company Claim		9,699	
3. Recommended Adjustment			$1,044
4. 2018 Rate Counsel Assessment		$2,378	
5. Company Claim		2,366	
6. Recommended Adjustment			($12)
7. Total Recommended Adjustment			$1,033
8. Income Taxes @	28.11%		290
9. Operating Income Impact			**$742**

Sources:
(A) Company Filing, Workpaper to Schedule SSJ-48, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INTEREST SYNCHRONIZATION ($000)

1. Pro Forma Rate Base		$5,464,734	(A)
2. Weighted Cost of Debt		1.84%	(B)
3. Pro Forma Interest Expense		$100,553	
4. Company Claim		104,176	(C)
5. Recommended Adjustment		$3,623	
6. Increase in Income Taxes @	28.11%	**$1,018**	

Sources:
(A) Schedule ACC-3E.
(B) Schedule ACC-2E.
(C) Company Filing, Exhibit P-2, Schedule SSJ-29, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INCOME TAX RATE

1. Revenue		100.00%	
2. State Income Taxes @	9.00%	9.00%	(A)
3. Federal Taxable Income		91.00%	
4. Income Taxes @	21.00%	19.11%	(A)
5. Operating Income		71.89%	
6. Total Tax Rate		**28.11%**	(B)

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-06, R-1.
(B) Line 1 - Line 5.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REVENUE MULTIPLIER

1.	Revenue		100.00%	
	Less:			
2.	BPU Assessments		0.19%	(A)
3.	RC Assessments		0.05%	(A)
4.	Uncollectibles		0.00%	(A)
5.	Taxable Income		99.75%	
6.	State Income Taxes @	9.00%	8.98%	(A)
7.	Federal Taxable Income		90.78%	
8.	Income Taxes @	21.00%	19.06%	(A)
9.	Operating Income		71.71%	
10.	Total Tax Rate		**28.04%**	(B)
11.	Revenue Multiplier		**1.3944**	(C)

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-06, R-1.
(B) Line 6 + Line 8.
(C) Line 1 / Line 9.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS ($000)

1.	Capital Structure/Cost of Capital	($60,551)
	Rate Base Adjustments:	
2.	Utility Plant in Service - Post Test Year	(12,351)
3.	Utility Plant in Service - TrakSmart	(7)
4.	Plant Held for Future Use	(46)
5.	Accumulated Depreciation	11,684
6.	Cash Working Capital	(19,107)
7.	Accumulated Deferred Taxes	1,818
8.	Consolidated Income Taxes	(1,149)
	Operating Income Adjustments	
9.	Pro Forma Revenue - Weather Normalization	580
10.	Salary and Wage Expense	(828)
11.	Incentive Compensation Program Expense	(11,906)
12.	Payroll Tax Expense	(885)
13.	Fringe Benefits	(1,305)
14.	Pension Expense	(15,999)
15.	Rate Case Expense	(241)
16.	Storm Damage Expense	47,566
17.	Regulatory Asset Amortization Expense	122
18.	COLI Interest Expense	(4,424)
19.	Insurance Expense	(121)
20.	Credit Card Fee Expense	(4,240)
21.	Other Compensation Expense - NEOs	(63)
22.	Meals and Entertainment Expense	(561)
23.	Industry Dues Expense	(124)
24.	Real Estate Tax Expense	(535)
25.	Depreciation Expense - Plant-in-Service	(4,188)
26.	Depreciation Expense - New Rates	(57,464)
27.	Depreciation Expense - Rate Counsel Rates	(27,446)
28.	BPU and Rate Counsel Assessments	(1,035)
29.	Interest Synchronization	1,420
30.	Total Recommended Adjustments (Excl. Tax Adj.)	($161,387)
31.	Company Claim	199,788
32.	Recommended Revenue Deficiency (Excl. Tax Adj.)	**$38,402**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REVENUE REQUIREMENT SUMMARY ($000)

	Company Claim	Recommended Adjustment	Recommended Position	
	(A)			
1. Pro Forma Rate Base	$4,165,737	($285,814)	$3,879,923	(B)
2. Required Cost of Capital	7.39%	-0.77%	6.62%	(C)
3. Required Return	$307,848	($50,825)	$257,023	
4. Operating Income @ Present Rates	140,559	93,271	233,830	(D)
5. Operating Income Deficiency	$167,289	($144,096)	$23,193	
6. Revenue Multiplier	1.4200	1.4200	1.4200	(E)
7. Revenue Increase Excl. Tax Adj.	$237,550	($204,617)	$32,933	
8. Roll in of Tax Refunds			(139,676)	(F)
9. Total Base Rate Reduction			**($106,743)**	

Sources:
(A) Company Filing, Schedule P-2, Schedule SSJ-2, R-1.
(B) Schedule ACC-2G.
(C) Schedule ACC-3G.
(D) Schedule ACC-12G.
(E) Schedule ACC-33G.
(F) Schedule ACC-Tax.

Schedule ACC-2G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REQUIRED COST OF CAPITAL ($ MILLIONS)

	Capital Structure (%	Cost Rate (%)	Weighted Cost (%)
	(A)	(A)	
1. Long Term Debt	46.36%	3.96%	1.84%
2. Customer Deposits	0.48%	0.87%	0.00%
3. Common Equity	53.16%	9.00%	4.78%
4. Total Cost of Capital	100.00%		**6.62%**

Sources:
(A) Testimony of Mr. Kahal, Schedule MIK-1, page 1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
RATE BASE SUMMARY ($000)

	Company Claim (A)	Recommended Adjustment		Recommended Position
1. Utility Plant in Service	$8,251,685	($324,254)	(B)	$7,927,431
2. Plant Held for Future Use	96	(96)	(C)	$0
Less:				
3. Accumulated Depreciation	(2,462,602)	100,305	(D)	(2,362,297)
4. Advances for Construction	(18,696)	0		(18,696)
5. Net Utility Plant	$5,770,483	($224,045)		$5,546,438
Plus:				
6. Cash Working Capital	$249,813	($156,408)	(E)	$93,405
7. Materials and Supplies	39,302	0		39,302
8. Prepayments	364	0		364
Less:				
9. Customer Deposits	$0	$0		$0
10. Accumulated Deferred Taxes	(1,678,546)	36,590	(F)	(1,641,956)
11. Consolidated Income Taxes	(157)	(3,508)	(G)	(3,665)
12. GSMP Roll-in #3	(215,522)	61,557	(H)	(153,965)
13. Total Rate Base	**$4,165,737**	**($285,814)**		**$3,879,923**

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-3, R-1.
(B) Schedule ACC-4G and Schedule ACC-5G.
(C) Schedule ACC-6G.
(D) Schedule ACC-7G.
(E) Schedule ACC-8G.
(F) Schedule ACC-9G.
(G) Schedule ACC-10G.
(H) Schedule ACC-11G.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
UTILITY PLANT IN SERVICE ($000)

1.	Test Year Ending Balance	$7,927,499	(A)
2.	Company Claimed Plant	8,251,685	(A)
3.	Recommended Adjustment	**($324,186)**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-7, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
UTILITY PLANT IN SERVICE - TRAKSMART ($000)

1.	Amount Included in Rate Base	$68	(A)
2.	Recommended Adjustment	**($68)**	

Sources:
(A) Per Company at informal discovery conference, 6/29/18.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
PLANT HELD FOR FUTURE USE ($000)

1.	Company Claim	$96	(A)
2.	Recommended Adjustment	**($96)**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-3, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
ACCUMULATED DEPRECIATION-POST TEST YEAR ($000)

1.	Test Year Ending Balance	($2,362,297)	(A)
2.	Company Claim	(2,462,602)	(A)
3.	Recommended Adjustment	**$100,305**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-9, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
CASH WORKING CAPITAL ($000)

1.	Recommended Cash Working Capital	$93,405	(A)
2.	Company Claim	249,813	(B)
3.	Recommended Adjustment	**($156,408)**	

Sources:
(A) Reflects Rate Counsel adjustments. See Crane CWC Workpaper.
(B) Company Filing, Exhibit P-8, R-1, Schedule HW-1, R-1.

Schedule ACC-9G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
DEFERRED INCOME TAX RESERVE ($000)

1.	Test Year Ending Balance	($1,641,956)	(A)
2.	Company Claim	(1,678,546)	(A)
3.	Recommended Adjustment	**$36,590**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-13, R-1.

Schedule ACC-10G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
CONSOLIDATED INCOME TAXES ($000)

1. Sum of Net Taxable Losses for Companies With Cumulative Taxable Losses	($150,997)	(A)
2. Tax Loss Benefit Based on Annual Federal Income Tax Rate	(52,849)	(A)
3. Share of PSE&G-Electric Cumulative Positive Taxable Income to Total for Companies With Cumulative Taxable Income	31.52%	(A)
4. Total CIT Adjustment for PSE&G	($16,658)	
5. Gas Percentage	22.00%	
6. Gas Adjustment	**($3,665)**	

Sources:
(A) Reflects Rate Counsel adjustments to Exhibit P-4, R-1, Schedule RCK-6A, R-1. See Crane CTA Workpaper.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
GSMP ROLL IN #3

1.	Test Year Actual Balance	$153,965	(A)
2.	Company Claim	215,522	(A)
3.	Recommended Adjustment	**$61,557**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-15, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
OPERATING INCOME SUMMARY ($000)

			Schedule
1.	Company Claim	$140,559	
	Recommended Adjustments:		
2.	Salary and Wage Expense	899	13G
3.	Incentive Compensation Program Expense	7,947	14G
4.	Payroll Tax Expense	615	15G
5.	Fringe Benefits Expense	12,498	16G
6.	Pension Expense	10,500	17G
7.	Rate Case Expense	54	18G
8.	Storm Damage Expense	(1,085)	19G
9.	COLI Interest Expense	933	20G
10.	Insurance Expense	78	21G
11.	Credit Card Fee Expense	1,679	22G
12.	Other Compensation Expense - NEOs	34	23G
13.	Meals and Entertainment Expense	345	24G
14.	Industry Dues Expense	89	25G
15.	Real Estate Tax Expense	147	26G
16.	Depreciation Expense - Plant-in-Service	4,073	27G
17.	Depreciation Expense - New Rates	49,682	28G
18.	Depreciation Expense - Rate Counsel Expense	5,943	29G
19.	BPU and RC Assessments	278	30G
20.	Interest Synchronization	(1,438)	31G
21.	Operating Income	**$233,830**	

Schedule ACC-13G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
SALARY AND WAGE EXPENSE ($000)

1.	Company Claim		$6,634	(A)
2.	Rate Counsel Recommendation		5,383	(B)
3.	Recommended Adjustment		$1,251	
4.	Income Taxes @	28.11%	352	
5.	Operating Income Impact		**$899**	

Sources:
(A) Company Exhibit P-2, Schedule SSJ-27, R-1.
(B) Reflects annualization of first nine months of Test Year and elimination of 2019 increases. See Crane Salary Workpapers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INCENTIVE COMPENSATION PROGRAM EXPENSE ($000)

1. Employee Incentive Compensation		$12,310	(A)
2. Recommended Adjustment (%)		50.00%	(B)
3. Recommended Adjustment ($)		$6,155	
4. Officer Incentive Compensation		4,899	(C)
5. Total Recommended Adjustment		$11,054	
6. Income Taxes @	28.11%	3,107	
7. Operating Income Impact		**$7,947**	

Sources:
(A) Average of 2016 and 2017 Expense per the reponse to RCR-A-141.
(B) Recommendation of Ms. Crane.
(C) Response to RCR-A-142.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
PAYROLL TAX EXPENSE ($000)

1.	Salary and Wage Adjustment		$1,251	(A)
2.	Incentive Compensation Adjustment		11,054	(B)
3.	Total Recommended Adjustments		$12,305	
4.	Tax Rate Per Company		6.95%	(C)
5.	Recommended Payroll Tax Adjustment		$855	
6.	Income Taxes @	28.11%	240	
7.	Operating Income Impact		**$615**	

Sources:
(A) Schedule ACC-13G.
(B) Schedule ACC-14G.
(C) Payroll Tax Workpapers per Company.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
FRINGE BENEFITS EXPENSE ($000)

1. Test Year Fringe Benefit Cost Excluding Pension		$43,984	(A)
2. Company Claim		61,369	(A)
3. Recommended Adjustment		$17,385	
4. Income Taxes @	28.11%	4,887	
5. Operating Income Impact		**$12,498**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-30, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
PENSION EXPENSE ($000)

1.	Test Year Actual		($14,605)	(A)
2.	Company Claim		0	(A)
3.	Recommended Adjustment		$14,605	
4.	Income Taxes @	28.11%	4,105	
5.	Operating Income Impact		**$10,500**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-30, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
RATE CASE EXPENSE ($000)

1.	Company Claim		$453	(A)
2.	Recommended Amortization Period		3	(B)
3.	Annual Amortization		$151	
4.	Allocation to Ratepayers (%)		50.00%	(C)
5.	Allocation to Ratepayers ($)		$76	
6.	Company Claim - Annual Expense		151	
7.	Recommended Adjustment		$76	
8.	Income Taxes @	28.11%	21	
9.	Operating Income Impact		**$54**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-44, R-1.
(B) Recommendation of Ms. Crane.
(C) Reflects BPU Policy of 50/50 sharing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
STORM DAMAGE EXPENSE ($000)

1. 2010-2012 Deferred Storm Costs		$7,545	(A)
2. Test Year Deferred Storm Costs		0	(B)
3. Total Amount to be Amortized		$7,545	
4. Proposed Amortization Period		5	(C)
5. Annual Amortization		$1,509	
6. Income Taxes @	28.11%	424	
7. Operating Income Reduction		**$1,085**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-39, R-1.
(B) Company Filing, Exhibit P-2, Schedule SSJ-40, R-1.
(C) Recommendation of Ms. Crane.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
COLI INTEREST EXPENSE ($000)

1.	Company Claim	$933	(A)
2.	Operating Income Impact	**$933**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-31, R-1.

Schedule ACC-21G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INSURANCE EXPENSE ($000)

1	Test Year Actual		$2,381	(A)
2.	Company Claim		2,489	(A)
3.	Recommended Adjustment		$108	
4.	Income Taxes @	28.11%	30	
5.	Operating Income Impact		**$78**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-35, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
CREDIT CARD FEE EXPENSE ($000)

1.	Recommended Adjustment		$2,336	(A)
2.	Income Taxes @	28.11%	657	
3.	Operating Income Impact		**$1,679**	

Sources:
(B) Company Filing, Schedule SSJ-45, R-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
OTHER COMPENSATION EXPENSE - NEOS

1.	Total Other Compensation - NEOs		$381	(A)
2.	Less 401K Match		65	(B)
3.	Recommended Adjustment		$316	
4.	Allocation to Electric (%)		15.0%	(C)
5.	Recommended Electric Adjustment		$47	
6.	Income Taxes @	28.11%	13	
7.	Operating Income Impact		**$34**	

Souces:

(A) 2018 Proxy Statement, page 66.
(B) 2018 Proxy Statement, page 67.
(C) Per Company, informal discovery on June 29, 2018.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
MEALS AND ENTERTAINMENT EXPENSE ($000)

1.	Recommended Adjustment		$480	(A)
2.	Income Taxes @	28.11%	135	
3.	Operating Income Impact		**$345**	

Sources:
(A) Response to RCR-A-89.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INDUSTRY DUES EXPENSE ($000)

1.	Company Claim		$617	(A)
2.	Recommended Adjustment (%)		20.00%	(B)
3.	Recommended Adjustment ($)		$123	
4.	Income Taxes @	28.11%	35	
5.	Operating Income Impact		**$89**	

Sources:
(A) Response to RCR-A-87.
(B) Recommendation of Ms. Crane.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REAL ESTATE TAX EXPENSE ($000)

1.	Annualized Cost @ June 30, 2018		$5,140	(A)
2.	Company Claim		5,345	(B)
3.	Total Recommended Tax Adjustment		$205	
4.	Income Taxes @	28.11%	58	
5.	Recommended Adjustment		**$147**	

Sources:
(A) Based on annualizing June 2018 expense per Company workpaper.
(B) Company Filing, Exhibit P-2, Schedule SSJ-34, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
DEPRECIATION EXPENSE - PLANT-IN-SERVICE ($000)

1. Annualized Depreciation @ June 30, 2018		$162,608	(A)
2. Annualized Depreciation @ Dec. 31, 2018		168,273	(A)
3. Recommended Adjustment		$5,665	
4. Income Taxes @	28.11%	1,592	
5. Operating Income Impact		**$4,073**	

Sources:
(A) Workpaper to Company Filing, Exhibit P-2, Schedule SSJ-38, R-1.

Schedule ACC-28G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
DEPRECIATION EXPENSE - NEW RATES ($000)

1.	Annualized Depreciation @ 12/31/18 - New Rates		$237,382	(A)
2.	Annualized Depreciation @ 12/31/18 - Old Rates		168,273	(A)
3.	Recommended Adjustment		$69,109	
4.	Income Taxes @	28.11%	19,427	
5.	Operating Income Impact		**$49,682**	

Sources:
(A) Workpaper to Company Filing, Exhibit P-2, Schedule SSJ-38, R-1.

Schedule ACC-29G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
DEPRECIATION EXPENSE - RATE COUNSEL RATES ($000)

1.	Annualized Depreciation @ June 30, 2018 Per Company		$162,608	(A)
2.	Annualized Depreciation @ June 30, 2018 Per Rate Counsel		154,341	(B)
3.	Recommended Adjustment		$8,267	
4.	Income Taxes @	28.11%	2,324	
5.	Operating Income Impact		**$5,943**	

Sources:
(A) Workpaper to Company Filing, Exhibit P-2, Schedule SSJ-38, R-1.
(B) Depreciation Workpaper of Mr. Garren.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
BPU AND RATE COUNSEL ASSESSMENTS ($000)

		(A)	
1. 2018 BPU Assessment		$3,150	
2. Company Claim		3,540	
3. Recommended Adjustment			$390
4. 2018 Rate Counsel Assessment		$865	
5. Company Claim		863	
6. Recommended Adjustment			($2)
7. Total Recommended Adjustment			$387
8. Income Taxes @	28.11%		109
9. Operating Income Impact			**$278**

Sources:
(A) Company Filing, Workpaper to Schedule SSJ-48, R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INTEREST SYNCHRONIZATION ($000)

1. Pro Forma Rate Base		$3,879,923	(A)
2. Weighted Cost of Debt		1.84%	(B)
3. Pro Forma Interest Expense		$71,392	
4. Company Claim		76,509	(C)
5. Recommended Adjustment		$5,117	
6. Increase in Income Taxes @	28.11%	**$1,438**	

Sources:
(A) Schedule ACC-3G.
(B) Schedule ACC-2G.
(C) Company Filing, Exhibit P-2, Schedule SSJ-29, R-1.

Schedule ACC-32G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
INCOME TAX RATE

1. Revenue		100.00%	
2. State Income Taxes @	9.00%	9.00%	(A)
3. Federal Taxable Income		91.00%	
4. Income Taxes @	21.00%	19.11%	(A)
5. Operating Income		71.89%	
6. Total Tax Rate		**28.11%**	(B)

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-06, R-1.
(B) Line 1 - Line 5.

Schedule ACC-33G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REVENUE MULTIPLIER

1.	Revenue		100.00%	
	Less:			
2.	BPU Assessments		0.19%	(A)
3.	RC Assessments		0.05%	(A)
4.	Uncollectibles		1.80%	(A)
5.	Taxable Income		97.96%	
6.	State Income Taxes @	9.00%	8.82%	(A)
7.	Federal Taxable Income		89.14%	
8.	Income Taxes @	21.00%	18.72%	(A)
9.	Operating Income		70.42%	
10.	Total Tax Rate		**27.54%**	(B)
11.	Revenue Multiplier		**1.4200**	(C)

Sources:
(A) Company Filing, Exhibit P-2, Schedule SSJ-06, R-1.
(B) Line 6 + Line 8.
(C) Line 1 / Line 9.

Schedule ACC-34G

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING JUNE 30, 2018
REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS ($000)

1.	Capital Structure/Cost of Capital	($45,286)
	Rate Base Adjustments:	
2.	Utility Plant in Service - Post Test Year	(30,495)
3.	Utility Plant in Service - TrakSmart	(6)
4.	Plant Held for Future Use	(9)
5.	Accumulated Depreciation	9,435
6.	Cash Working Capital	(14,713)
7.	Accumulated Deferred Taxes	3,442
8.	Consolidated Income Taxes	(330)
9.	GSMP Roll in #3	5,790
	Operating Income Adjustments	
10.	Salary and Wage Expense	(1,277)
11.	Incentive Compensation Program Expense	(11,284)
12.	Payroll Tax Expense	(873)
13.	Fringe Benefits Expense	(17,747)
14.	Pension Expense	(14,909)
15.	Rate Case Expense	(77)
16.	Storm Damage Expense	1,540
17.	COLI Interest Expense	(1,325)
18.	Insurance Expense	(110)
19.	Credit Card Fee Expense	(2,385)
20.	Other Compensation Expense - NEOs	(48)
21.	Meals and Entertainment Expense	(490)
22.	Industry Dues Expense	(126)
23.	Real Estate Tax Expense	(209)
24.	Depreciation Expense - Plant-in-Service	(5,783)
25.	Depreciation Expense - New Rates	(70,549)
26.	Depreciation Expense - Rate Counsel Expense	(8,439)
27.	BPU and RC Assessments	(395)
28.	Interest Synchronization	2,043
29.	Total Recommended Adjustments (Excl. Tax Adj.)	($204,617)
30.	Company Claim	237,550
31.	Recommended Revenue Deficiency (Excl. Tax Adj.)	**$32,933**