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

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS RATES, DEPRECIATION RATES FOR GAS PROPERTY, AND FOR CHANGES IN THE TARIFF FOR GAS SERVICE, B.P.U.N.J. NO. 13, GAS PURSUANT TO N.J.S.A. 48:2-18, 48:2-21 AND 48:2-21.1	)	**BPU DKT. NO. GR05100845** **OAL DKT. NO. PUC-1747-06**

DIRECT TESTIMONY AND EXHIBITS OF ROBERT J. HENKES ON BEHALF OF THE NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BPU Docket No. GR05100845
OAL Docket No. PUC-1747-06
Direct Testimony of Robert J. Henkes

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes and my business address is 7 Sunset Road, Old Greenwich, Connecticut 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting I performed the same type of consulting services as I am currently rendering through Henkes

Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

III. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF THIS TESTIMONY?

A. I was engaged by the New Jersey Division of the Ratepayer Advocate ("Ratepayer Advocate") to conduct a review and analysis and present testimony in the matter of the petition of Public Service Electric and Gas Company ("PSE&G" or "the Company") for approval of an increase in its base rates for gas service.

The purpose of this testimony is to present to Your Honor and the New Jersey Board of Public Utilities ("BPU" or "the Board") the appropriate pro forma rate base and pro forma operating income, as well as the appropriate revenue requirement for the Company in this proceeding.

In determining the recommended revenue requirement positions contained in this testimony, I have adopted the recommendations of <u>Matthew Kaha</u>l regarding the Company's overall rate of return; <u>Michael Majoros</u> regarding the appropriate gas plant depreciation rates and the amortization of a cost of removal related regulatory liability; <u>Richard Lelash</u> regarding the Company's proposed Price Elasticity adjustment; and Brian Kalcic regarding certain Western Union Customer Payment Center surcharges.

In developing this testimony, I have reviewed and analyzed the Company's petition; originally filed 6+6 and updated 12+0 testimonies, exhibits and workpapers;

responses to interrogatories and other relevant financial documents and data.

Q. WHAT IS THE STARTING POINT YOU HAVE USED IN THE PREPARATION OF THIS TESTIMONY AND THE ACCOMPANYING SCHEDULES RJH-1 THROUGH RJH-19?

A. PSE&G filed this case on September 30, 2005 based on a test year ended September 30, 2005. In this original filing, all of the Company's unadjusted test year filing data was based on 6 months actual and 6 months projected financial results.[1] This 6+6 filing indicated the need for a rate increase of $132.8 million. On February 28, 2006, the Company revised and updated its original filing based on 12 months of actual test year results. This revised and updated filing, referred to as the "12+0" filing, increased the amount of the originally requested rate increase from $132.8 million to $136.9 million.

I have used the Company's revised and updated 12+0 filing as the starting point of my analyses. The following testimony and accompanying schedules RJH-1 through RJH-19 describe all of the recommended adjustments made by me to this starting point in order to arrive at the Ratepayer Advocate's overall recommendations regarding PSE&G's gas rate of return, rate base, operating income and resulting revenue requirement.

Q. HAS THE COMPANY ADJUSTED THE TEST YEAR RESULTS TO

[1] This filing is referred to as the "6+6" filing.

REFLECT THE IMPACTS OF THE PROPOSED PSEG/EXELON MERGER?

A. No. The Company has filed this case under "business as usual" conditions that assume none of the merger-driven operational, structural and financial changes and net synergy savings that are currently being addressed in the pending merger proceeding in BPU Docket No. EM05020106.

IV. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. The findings and conclusions reached by me in this case are summarized on Schedule RJH-1 and are as follows:

1. The appropriate pro forma rate base amounts to $1,770,967,000 which is $181,874,000 lower than the Company's proposed 12+0 pro forma rate base of $1,952,841,000 (see Schedule RJH-1, line 1 and Schedule RJH-3).

2. The appropriate pro forma operating income amounts to $177,069,000, which is $91,647,000 higher than the Company's proposed 12+0 pro forma operating income of $85,422,000 (see Schedule RJH-1, line 4 and Schedule RJH-4).

3. Ratepayer Advocate rate of return witness Matthew Kahal has recommended an appropriate overall rate of return for this Company of 7.66%. This recommended overall rate of return number incorporates a recommended return on equity requirement of 9.50%. The recommended overall rate of return of 7.66% is lower than the Company's proposed overall rate of return of 8.51%, which incorporates a return on equity rate of 11.00% (see Schedule RJH-1, line 2 and Schedule RJH-2).

4. The appropriate revenue conversion factor in this case is 1.6946, similar to what PSE&G has proposed. (see Schedule RJH-1, line 6).

5. The four recommended rate making components described in points 1 through 4 above indicate the need for an annual rate decrease of $70,264,000. This is $207,128,000 lower than the Company's proposed 12+0 rate increase claim of $136,864,000 (see Schedule RJH-1, line 7).

IV. REVENUE REQUIREMENT ISSUES

A. RATE BASE

Q. HAVE YOU SUMMARIZED THE COMPANY'S PROPOSED AND YOUR RECOMMENDED RATE BASE POSITIONS?

A. Yes. The Company's proposed pro forma 12+0 rate base of $1,952,841,000 is summarized by specific rate base component on Schedule RJH-3. As shown on this schedule, I have recommended a pro forma rate base of $1,770,967 by making four rate base adjustments with the net effect of decreasing the Company's proposed rate base by a total amount of $181,873,000. Each of these recommended rate base adjustments will be discussed in detail below.

- <u>Accumulated Depreciation Reserve</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPANY'S ACCUMULATED DEPRECIATION RESERVE BALANCE, AS SHOWN ON SCHEDULE RJH-3, LINE 2.

A. As shown on Schedule RJH-5, the Company's proposed pro forma test year-end depreciation reserve balance consists of its actual per books depreciation reserve balance as of the end of the test year, September 30, 2005, plus one-half of the difference between the Company's proposed annualized depreciation expenses and the actual test year depreciation expenses. Similar to this rate making approach, the Ratepayer Advocate's recommended pro forma depreciation reserve balance starts out with the actual September 30, 2005 reserve balance plus one-half of the difference between the Ratepayer Advocate's proposed annualized depreciation expenses (net of the amortization of the Cost of Removal Regulatory Liability) and the actual test year depreciation expenses. This results in a total recommended pro forma depreciation reserve balance of $1,768,636,000, which is $61,928,000 lower than the Company's proposed pro forma depreciation reserve balance of $1,830,564,000. The approximate $61.9 million difference between the Company's proposed and the Ratepayer Advocate's recommended depreciation reserve balances represents the "flow-through" effect of Mr. Majoros' recommended depreciation expense adjustments.

- Lead/Lag Study Cash Working Capital

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S PROPOSED CASH WORKING CAPITAL ("CWC") ALLOWANCE IN THIS CASE.

A. The Company's proposed cash working capital requirement consists of two components. The first component is the cash working capital determined by use of a detailed lead/lag study. The results of this lead/lag study, indicating a total requirement of $154.455 million, are summarized on Mr. Moscufo's Schedule MPM-2 R-1. The second component is the Net Assets and Liabilities balance for the test year, representing the uses and sources of cash funds by those assets and liabilities that have not already been accounted for in the lead/lag study or as separate rate base items. As summarized on Mr. Furlong's Schedule DMF-1 R-1, this Net Assets and Liabilities balance amounts to a negative cash working capital requirement of $1.057 million, thereby offsetting the $154.455 million positive lead/lag study cash working capital. In summary, the Company's proposed net cash working capital request in this case is $153.398 million, as shown on Mr. Moscufo's Schedule MPM-1 R-1.

Q. WHAT IS YOUR POSITION IN THIS CASE REGARDING MR. FURLONG'S PROPOSED NET ASSETS AND LIABILITIES CASH WORKING CAPITAL BALANCE?

A. Based on my review and analysis of Mr. Furlong's Net Assets and Liabilities study summarized on Schedule DMF-1 R-1, I find these study results to be reasonable. I have therefore accepted the Company's proposed cash working capital reduction of $1.057 million, as shown on my summary rate base Schedule RJH-3, line 4b.

Q. TURNING NOW TO MR. MOSCUFO'S LEAD/LAG STUDY, DO YOU AGREE WITH THE LEAD/LAG DAYS EMPLOYED IN HIS STUDY?

A. Yes. Based on my review of Mr. Moscufo's lead/lag study, I agree with all of the lead/lag days for revenues, expenses and taxes that are summarized on his Schedule MPM-2 R-1.

Q. DO YOU AGREE WITH ALL OF THE REVENUE REQUIREMENT COMPONENTS INCLUDED IN MR. MOSCUFO'S LEAD/LAG STUDY?

A. No, I do not agree with Mr. Moscufo's proposal to include depreciation expenses, deferred income taxes and invested capital with assumed payment lags of 0 days in the study.

Q. COULD YOU EXPLAIN YOUR DISAGREEMENTS IN MORE DETAIL?

A. Yes. I believe that a properly conducted lead-lag study (1) should *exclude* non-cash depreciation expenses and deferred income taxes, (2) should *exclude* the return on equity, and (3) should *include* debt interest with appropriate payment lags. In general, the appropriate cash working capital should be based on the timing differences between the payment of cash expenses and taxes and the receipt of cash operating revenues. Depreciation and deferred taxes simply do not represent or require cash outlays during the lead/lag study period. Therefore, these non-cash expenses should be removed from the lead/lag study.

Q. IS YOUR RECOMMENDATION TO REMOVE DEFERRED TAXES FROM THE LEAD LAG STUDY FOR PURPOSES OF DETERMINING THE COMPANY'S CASH WORKING CAPITAL CONSISTENT WITH WELL-ESTABLISHED BPU RATE MAKING POLICY?

A. Yes. The policy to remove deferred taxes from the lead/lag study in calculating the appropriate cash working capital requirement was most notably established in a prior PSE&G base rate proceeding, Docket No. ER85121163. The Board reiterated this rate making policy in a subsequent rate case involving Elizabethtown Gas Company, Docket GR88121321. On page 7 of its Order[2] dated February 1, 1990 in

[2] Order Adopting In Part And Modifying In Part The Initial Decision, I/M/O The Petition Of

that case, the Board stated with regard to this cash working capital issue:

> Cash Working Capital
> ...Petitioner presented a lead-lag study to calculate cash working capital requirements....
>
> With respect to deferred taxes, Petitioner recommended including deferred taxes of $1,259,000 as a component of its cash working capital requirements. Petitioner argued that there was a collection lag in recovering deferred taxes because of the deferred tax liability associated with utility plant. Rate Counsel recommended that deferred taxes be excluded from the lead-lag study since deferred taxes are a non-cash item and do not require investor supplied capital.
>
> Staff recommends that deferred taxes be excluded from the lead-lag study. Staff contends that this recommendation is consistent with prior Board treatment of deferred taxes, most notably in the PSE&G rate case, (Docket No. ER85121163) wherein the Board removed deferred taxes from cash working capital. The ALJ was persuaded by Staff's argument as to the proper rate making treatment for deferred taxes. The ALJ recommended that deferred taxes be deducted from operating revenues in the working capital allowance for purposes of this proceeding. Initial Decision p. 21. The Board FINDS the ALJ's determination on deferred taxes to be reasonable and consistent with Board policy. Therefore, the Board ADOPTS the ALJ's conclusion on this issue....

The above Board ruling clearly establishes the rate making policy that deferred taxes are not to be considered in a lead/lag study for purposes of determining the appropriate cash working capital requirement in a rate proceeding.

Q. WHAT ABOUT THE CLAIMED CASH WORKING CAPITAL REQUIREMENT RELATED TO THE RETURN ON EQUITY?

A. This return element should not result in a cash working capital requirement. Even if one were to assume that there is a cash working capital requirement associated with

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Elizabethtown Gas Company For Approval Of Increased Base Tariff Rates And Charges For Gas Service And Other Tariff Revision, BPU Docket No. GR88121321.

the return on equity, this effect should already be incorporated in the equity return required by the common stock investor. The Company is essentially taking the position that the common shareholder is entitled to the return on his equity investment at the exact instant that service is rendered. I disagree with this fundamental assumption. While it may sound appropriate that the common shareholder is entitled to the return on his equity investment, it is a fact that the shareholder receives his return through the quarterly payments of dividends and any gain in the Company's stock. This is the mechanism by which the common shareholder is compensated in the real world. For the aforementioned reasons, I recommend that the return on equity be removed from the lead/lag study.

Q. WHY SHOULD THE PAYMENT LAG ASSOCIATED WITH DEBT INTEREST BE INCLUDED IN THE LEAD/LAG STUDY FOR PURPOSES OF DETERMINING THE COMPANY'S CASH WORKING CAPITAL?

A. Interest expenses for long-term debt are included as part of the Company's revenue requirement. Therefore, the rates paid by PSE&G's customers are set so as to produce, in addition to other amounts, the sums necessary to pay interest to bondholders. As utility services are used, the Company receives money from its ratepayers that partly serves to enable the Company to pay interest to its bondholders. However, the Company does not have to pay its bondholders interest immediately. It only pays interest to its bondholders twice a year. Thus, while long-term interest expense accrues on a daily basis, it is paid out semi-annually in a lump sum. This means that, on average, interest on long-term debt has a payment lag of 91.25 days (365/4). Stated differently, this means that the Company, from the moment it receives the revenues to cover its long-term debt interest expenses until the time it actually pays out the interest expenses to its bondholders, has such funds available for general working capital purposes.

Q. SHOULD THE AVAILABILITY OF FUNDS DUE TO THIS INTEREST PAYMENT LAG BE CONSIDERED IN THE DETERMINATION OF THE COMPANY'S WORKING CAPITAL REQUIREMENT?

A. Yes. The interest payments to be made to the bondholders are fixed by contract. They cannot be made earlier nor later than the specified date. In this, the bondholders are like the tax collector or any other creditor of the Company. To refuse to consider the source of working capital from the interest payment lag has the impact of penalizing the ratepayers who are providing revenues to pay all expenses, including interest expenses; and it would provide a windfall return to the Company's stockholders. The bondholder, who has a fixed interest on his bond, will not receive any benefits from the act of excluding the interest payment lag from working capital considerations. It will be the common stockholder who will be allowed to earn a return on such available funds, collected from the ratepayer through rates, if this interest payment lag is not recognized for rate making purposes. For all of these reasons, debt interest expenses should be included with the appropriate payment lag in the lead/lag study to determine the Company's cash working capital requirement.

Q. HAVE YOU ADJUSTED MR. MOSCUFO'S PROPOSED LEAD/LAG STUDY TO REFLECT THE AFOREMENTIONED FINDINGS AND CONCLUSIONS?

A. Yes. My revised lead/lag study calculations are detailed on Schedule RJH-6. As shown on this schedule, I have removed from Mr. Moscufo's lead/lag study the non-cash depreciation expenses and deferred income taxes and the entire Return on Capital line item, while adding the Company's proposed pro forma long term debt interest with a payment lag of 91.25 days.

Q. WHAT IS THE APPROPRIATE CASH WORKING CAPITAL AMOUNT THAT RESULTS FROM THE PREVIOUSLY DESCRIBED REVISIONS TO MR. MOSCUFO'S LEAD/LAG STUDY?

A. As shown on Schedule RJH-6, the appropriate lead/lag study cash working capital requirement to be recognized for rate making purposes in this case amounts to approximately $106.6 million. As summarized on Schedule RJH-3, line 4a, this is approximately $47.8 million less than the lead/lag study cash working capital requirement of approximately $154.5 million claimed by the Company.

- Accumulated Deferred Income Taxes

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED NET RATE BASE DEDUCTION FOR ACCUMULATED DEFERRED INCOME TAXES.

A. As shown in the first column of Schedule RJH-7, the Company has proposed a net rate base deduction balance of $375,377,000 for its projected 9/30/05 accumulated deferred income taxes ("ADIT"). It should be recognized that this proposed net ADIT balance of $375.4 million does not reflect *all* of the Company's accumulated deferred income taxes as of 9/30/05, but only certain selected categories of the Company's total accumulated deferred income taxes.

Q. WHAT CRITERION WAS USED BY THE COMPANY IN ITS DETERMINATION OF THE SELECTED ADIT CATEGORIES TO BE GIVEN RATE BASE CONSIDERATION?

A. The Company has only reflected those accumulated deferred tax categories that are directly related to other rate base components. For example, the ADIT balances for Liberalized Depreciation, Cost of Removal, Computer Software, Capitalized Interest, NJ Corporate Business Tax, and the depreciation study impact are all directly related to the Company's proposed plant in service and depreciation reserve balances in rate base. The Company has therefore also given rate base recognition to the associated accumulated deferred income taxes.

Q. DO YOU AGREE WITH THE COMPANY'S EMPLOYED CRITERION THAT ONLY THOSE ACCUMULATED DEFERRED TAX CATEGORIES THAT DIRECTLY RELATE TO OTHER RATE BASE COMPONENTS BE CONSIDERED FOR RATE MAKING PURPOSES?

A. No. I disagree for the reason that the Company's employed criterion is incomplete. The proper criterion to use is: those accumulated deferred income taxes that relate directly to *other rate base components or to components of capital structure in the Company's overall rate of return calculation* can appropriately be considered for rate making purposes. As previously discussed, the Company's proposed net ADIT rate base balance consists of deferred taxes that are solely related to other items that are included in rate base. The Company has not considered rate base inclusion of accumulated deferred income taxes related to capital structure components.

Q. ARE THERE ACCUMULATED DEFERRED INCOME TAXES THAT ARE DIRECTLY RELATED TO CAPITAL STRUCTURE COMPONENTS?

A. Yes. These concern the accumulated deferred income taxes associated with the Company's unamortized Loss on Reacquired Debt balance. In calculating the proposed embedded cost of long-term debt rate in the capital structure claimed for rate making purposes in this case, the Company reduced its long term debt proceeds balance with the unamortized Loss on Reacquired Debt balance and added the amortization of its Loss on Reacquired Debt to the debt cost. The effect of this is that it increased the Company's effective cost of long-term debt in the Company's overall rate of return claim.

In summary, the unamortized Loss on Reacquired Debt balance has been used by the Company to increase its effective embedded cost of debt in the claimed overall rate of return number and, thereby, has increased the revenue requirement to be funded by the ratepayers. It would only be fair and appropriate to then also recognize the accumulated deferred income taxes associated with the unamortized

Loss on Reacquired Debt balance as a rate base deduction in this case, thereby partially offsetting the revenue requirement increase impact of the use of the unamortized Loss on Reacquired Debt balance in the Company's overall rate of return determination.

Q. WHAT IS THE SEPTEMBER 30, 2005 ACCUMULATED DEFERRED INCOME TAX BALANCE ASSOCIATED WITH THE COMPANY'S UNAMORTIZED LOSS ON REACQUIRED DEBT BALANCE?

A. As shown in filing workpaper page 22 and summarized on Schedule RJH-7, line 7, the accumulated deferred income tax balance directly related to the Company's unamortized loss on reacquired debt balance as of 9/30/05 amounts to $4,931,000. The recommended reflection of this additional ADIT category would further increase the Company's proposed net ADIT rate base deduction balance by $4,931,000.

Q. HAVE YOU MADE ANOTHER RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED RATE BASE BALANCE FOR ADIT?

A. Yes. As shown on Schedule RJH-7, the Company has reflected a negative ADIT balance of $8.593 million associated with its proposal to increase its current depreciation rates in this case. Based on Mr. Majoros' recommendation to *decrease* the Company's current depreciation rates, the Company's proposed negative ADIT balance component of $8.593 million would be eliminated. I have reflected this ADIT elimination on Schedule RJH-7, line 6.

Q. WHAT IS YOUR RECOMMENDED ADIT BALANCE TO BE USED FOR RATE MAKING PURPOSES IN THIS CASE BASED ON THE PREVIOUSLY DISCUSSED TWO RECOMMENDED ADJUSTMENTS TO THE COMPANY'S PROPOSED ADIT RATE BASE BALANCE?

A. As shown on Schedule RJH-7, I recommend that a total net ADIT balance of $388,901,000 be used as a rate base deduction in this case. This recommended net ADIT balance is approximately $13.5 million larger than the Company's proposed net ADIT balance and has the effect of reducing the Company's proposed rate base by that same amount of $13.5 million.

- <u>Consolidated Income Tax Benefits</u>

Q. DOES THE BOARD HAVE A POLICY WITH REGARD TO THE RATE MAKING TREATMENT OF TAX BENEFITS TO BE ASSIGNED TO REGULATED UTILITIES UNDER ITS JURISDICTION AS A RESULT OF THESE UTILITIES' PARTICIPATION IN CONSOLIDATED INCOME TAX RETURNS?

A. Yes. The Board has an established policy requiring that any tax savings allocable to a utility as a result of the filing of consolidated income tax returns be reflected as a rate base deduction in the utility's base rate filings. The BPU first established this policy in its Decision and Order ("D&O") in the Atlantic City Electric Company rate proceeding, BPU Docket No. ER90091090J, dated September 30, 1992. In this

D&O, the Board also ruled that the calculation starting point for the consolidated income tax related rate base deduction must be July 1, 1990:

> ...it is our judgment that the appropriate consolidated tax adjustment in this proceeding is to reflect as a rate base deduction the total of the 1991 consolidated tax savings benefits, and one-half of the tax benefits realized from AEI's 1990 consolidated tax filing...
>
> ...This finding reflects a balancing of the interests to reflect the unique period of uncertainty during the period 1987-1991. We hereby reaffirm and emphasize that the Board's policy is to reflect an equitable and appropriate sharing of consolidated tax benefits for ratepayers in future rate proceedings....

The Board reaffirmed its consolidated income tax policy in its D&O in a Jersey Central Power and Light Company ("JCP&L") base rate proceeding, BPU Docket No. ER91121820J, dated February 25, 1993. On pages 7 and 8 of its D&O in that docket the BPU stated:

> 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 the filing of a consolidated tax return. Income from utility operations provide the ability to produce tax savings for the entire GPU system because utility income is offset by the annual losses of the other subsidiaries. Therefore, the ratepayers who produce the income that provides the tax benefits should share in those benefits. The Appellate Division has repeatedly affirmed the Board's policy of requiring utility rates to reflect consolidated tax savings and the IRS has acknowledged that consolidated tax adjustments can be made and there are no regulations which prohibit such an adjustment.
>
> The issue, in this case, is not whether such an adjustment should be made, but, rather, what methodology should be used to make such an adjustment. In this area, the courts have held that the Board has the power and discretion to choose any approach which rationally determines a subsidiary utility's effective tax rate. <u>Toms River Water Company v. New Jersey Public Utilities Commissioners</u>, 158 <u>NJ Super</u> 57 (1978). Based on our review of the record in this case, the Board

> REJECTS the ALJ's recommendation to accept the income tax expense adjustment proposed by Petitioner and, instead, ADOPTS the position of Staff that the rate base adjustment is a more appropriate methodology for the reflection of consolidated tax savings. The rate base approach properly compensates ratepayers for the time value of money that is essentially lent cost-free to the holding companies in the form of tax advantages used currently and is consistent with our recent Atlantic Electric decision (Docket No. ER90091090J). Moreover, in order to maintain consistency with the methodology applied in the Atlantic decision, we modify the Staff calculation and find that a rate base adjustment which reflects consolidated tax savings from 1990 forward, including one-half of the 1990 savings, is appropriate in this case.

Q. DOES PSE&G FILE A CONSOLIDATED INCOME TAX RETURN?

A. Yes. The Company files a consolidated federal income tax return with the parent company, Public Service Enterprise Group ("PSEG"), and its other subsidiaries.

Q. HAVE YOU CALCULATED THE APPROPRIATE CONSOLIDATED INCOME TAX ADJUSTMENT TO BE APPLIED TO PSE&G FOR RATE MAKING PURPOSES IN THIS CASE IN ACCORDANCE WITH THE METHODOLOGY PREVIOUSLY ESTABLISHED BY THE BPU?

A. Yes. My calculations are detailed on Schedule RJH-8. As shown on this schedule, I recommend that the Company's rate base in this case be reduced by $182.4 million to reflect the impact of the consolidated income tax benefits accumulated from 1991 through 2005 that are allocable to PSE&G's regulated gas operations.

Q. PLEASE DISCUSS THE INFORMATION SHOWN ON SCHEDULE RJH-8 IN MORE DETAIL.

A. While the BPU has ruled that a utility's consolidated income tax benefits accumulated since mid-1990 can be considered for rate making purposes in a base rate proceeding, I have started my analysis regarding PSE&G's cumulative consolidated income tax benefits with the year 1991 and ended it with the year 2005. All of the tax data for the years 1991 through 2005 on Schedule RJH-8 are based on PSEG's actual consolidated income tax returns. The first three columns of the schedule show the total PSEG taxable income numbers for each year and the breakout of this total taxable income between the regulated PSE&G utility and the non-regulated operations of PSEG. It should be noted that for the years 1999 through 2005, the numbers in the "Regulated PSE&G" column reflect the taxable income from the regulated PSE&G electric and gas delivery operations and exclude the taxable income from the divested electric generation operations that were transferred to the non-regulated PSEG Power, Inc. Starting in 1999, the taxable income from PSEG Power is included in the "Non-Regulated PSEG Subsidiaries" column.

Next, I applied the Company's applicable statutory federal income tax rate to each of the annual taxable income losses/gain numbers from the non-regulated PSEG operations to arrive at the annual consolidated income tax benefits assignable to PSE&G in accordance with BPU-approved methodology. Next, I offset PSEG's actual Alternative Minimum Tax payments ("AMT") against the PSE&G-assigned consolidated income tax benefits. Again, this is in accordance with BPU-approved methodology. Finally, I applied PSE&G's actual Gas Delivery income tax ratios in order to arrive at the appropriate cumulative net income tax benefits for the 15-year period 1991 - 2005 assignable to PSE&G's Gas Delivery operations. As shown in the last column of Schedule RJH-8, this cumulative net consolidated income tax benefit amount is $182.4 million.

B. PRO FORMA OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND YOUR RECOMMENDED PRO FORMA OPERATING INCOME POSITIONS.

A. The Company has proposed a total pro forma test year operating income amount of $85,422,000 based on its 12+0 filing data. As shown on Schedule RJH-4, I have recommended a large number of operating income adjustments with the effect of increasing the Company's proposed pro forma operating income to a recommended pro forma test year operating income level of $177,069,000. Each of these recommended operating income adjustments will be discussed in detail below.

- Price Elasticity Adjustment

Q. WHAT IS THE REASON FOR THE PRICE ELASTICITY ADJUSTMENT SHOWN ON SCHEDULE RJH-4, LINE 2?

A. This adjustment, which increases the Company's proposed pro forma test year operating income by $5.557 million, reflects my adoption of Mr. Lelash's recommendation that the Company's proposed price elasticity adjustment be rejected by your Honor and the Board.

- <u>Test Year-End Customer Revenue Annualization</u>

Q. HAS THE COMPANY PROPOSED A REVENUE WEATHER NORMALIZATION ADJUSTMENT IN THIS CASE?

A. Yes. The Company's proposed weather normalization adjustment is described on pages 14-15 of Mr. Stellwag's 12+0 testimony. Schedule ANS-24 R-1 shows that the proposed weather normalization adjustment decreases the Company's revenue margin by approximately $5.7 million and net after-tax income by approximately $3.4 million. Through this adjustment, the Company has normalized the test year customer consumption levels based on 30-year average normalized weather determinants. The apparent reason for the Company's proposed revenue increase adjustment is that the actual 12+0 test year filing data contains weather that is colder than normal. The adjustment to normalize for this colder-than-normal test year weather results in a reduction in the actual test year level of gas consumption, which, in turn, reduces the test year margin revenues. Based on my review of the Company's proposed weather normalization methodology, I have accepted the Company's proposed revenue weather normalization adjustment.

Q. HAS THE COMPANY RESTATED ITS PROPOSED WEATHER-NORMALIZED TEST YEAR REVENUES TO REFLECT THE CUSTOMER LEVELS AS OF THE END OF THE TEST YEAR, SEPTEMBER 30, 2005?

A. No. The Company's proposed weather-normalized test year revenues are based upon the average customer level for the test year.

Q. DOES THIS REPRESENT AN ISSUE IN THIS CASE?

A. Yes. Since the Company has not annualized its proposed test year revenues for the growth in the number of customers, its proposed test year revenues are not properly "matched" with the Company's proposal to use a test year-end rate base and annualized depreciation expenses based on the test year-end plant in service in this proceeding.

Q. COULD YOU EXPLAIN THIS IN MORE DETAIL?

A. Yes. As discussed before, the Company's proposed test year revenues are based on the test year's average number of customers. In this regard, it is important to recognize that the plant investment that has supported the Company's average test year number of customers is the Company's average test year plant, not the (higher) September 2005 test year-end plant investment level. Since the Company has proposed the use of the higher test year-end plant in service balance and has annualized its depreciation expenses based on test year-end plant, it would be appropriate and consistent to annualize the revenues for the growth in customers up to the end of the test year.

Q. IS YOUR RECOMMENDATION TO REFLECT A REVENUE ANNUALIZATION ADJUSTMENT FOR CUSTOMER GROWTH UP TO

THE END OF THE TEST YEAR IN ACCORDANCE WITH BPU POLICY?

A. Yes. The BPU has a long-standing and well-established policy that the ratemaking use of test year-end rate base and annualized depreciation expenses based on test year-end plant be appropriately "matched" with the ratemaking use of annualized test year revenues based on customer growth up to the end of the test year. For example, in an earlier PSE&G base rate case, Docket No. 837-620, the Company proposed a test year-end rate base and depreciation annualization adjustment, but did not propose an offsetting and matching revenue annualization adjustment for customer growth up to the end of the test year. In that proceeding, the Board agreed with the ALJ's conclusion that:

> …a normalization adjustment should be made for test year-end customers. It is a proper adjustment because it matches the [test] year-end plant with the [test] year-end level of customers, and thus is consistent with the Board's clearly enunciated "matching" principle.

In PSE&G's next base rate case, BPU Docket No. ER85121163, the Company again proposed a test year-end rate base and depreciation annualization adjustment, and again did not propose an offsetting and matching revenue annualization adjustment for customer growth. In that proceeding, the Ratepayer Advocate (then Rate Counsel) and the BPU Staff proposed such a revenue annualization adjustment. On page 119 of his Initial Decision in that case, the ALJ stated:

> I agree with Staff and Rate Counsel that the Board has consistently recognized the appropriateness of this adjustment.

The BPU adopted the ALJ's reasoning and conclusions with regard to this revenue annualization adjustment. In that case, PSE&G also argued that a matching revenue annualization adjustment should not be made so as to afford the Company an attrition allowance. That argument was also rejected by the Board when it adopted the ALJ's findings and conclusions:

> …petitioner's attrition argument has been expressly addressed by the Board in Atlantic City Electric's most recent rate case, BPU Docket ER8504434, Decision and Order of the Board dated April 3, 1986 at p.3. After considering petitioner's earnings attrition argument I noted that the Board obviously considered same in the Atlantic City Electric case and that there is no just reason presented in this case to depart from Board policy….
> [ALJ Initial Decision, pp.119-120, OAL Docket No. PUC 231-86]

Q. WHAT SPECIFIC REVENUE ANNUALIZATION APPROACH AND METHODOLOGY DO YOU RECOMMEND BE USED IN THIS PROCEEDING IN ORDER TO ACCOMPLISH THIS YEAR-END RATE BASE VERSUS YEAR-END CUSTOMER GROWTH MATCHING?

A. A review of PSE&G's actual monthly gas customers throughout any particular year clearly shows that, while there is a general upward trend in number of customers, there are also significant customer fluctuations from month to month during the year. For example, the response to RAR-A-17(b) shows the following level of actual number of customers during the test year:

10/04	1,679,359
11/04	1,706,468
12/04	1,706,464
01/05	1,699,638
02/05	1,712,635
03/05	1,705,627
04/05	1,704,319
05/05	1,706,174
06/05	1,698,798
07/05	1,713,708
08/05	1,703,225
09/05	1,704,592

These monthly customer fluctuations could be caused by seasonal influences, monthly billing irregularities and additions and deletions of customers each month.

With monthly customer fluctuations as obvious as this, it would not be appropriate to then compare an actual "point in time" monthly customer level (such as the test year-end September 30, 2005) to the average test year customer level and then expect to draw the right customer growth and associated revenue annualization conclusions. For that reason, the revenue annualization for customer growth up to the end of the test year must be determined through a methodology different from merely a comparison of the September 30, 2005 number of customers to the average 2002 test year customers. This methodology is explained as follows.

It is reasonable to assume that the Company's actual average test year plant in service is approximately equivalent to the actual plant in service level during the mid-point of the test year. Therefore, the difference between the proposed test year-end plant level and the average test year plant level essentially represents one-half year's worth of growth in the Company's plant investment level. Since the Company's proposed test year revenues are based on the average number of customers, the appropriate revenue annualization adjustment should similarly be based on one-half year's worth of growth in the number of customers of the Company. In RAR-A-103, I requested the Company to determine the 5-year average annual compound customer growth rates using customer data for the years 2001-2005. I then requested the Company to calculate the revenue annualization adjustment for customer growth up to the end of the test year by : (1) taking one-half of the 5-year average annual compound customer growth rates; (2) applying these half-year growth rates to the average number of customers for the 12+0 test year to determine the test year "annualized" number of customers, consisting of the average test year number of customers plus one-half year's worth of customer growth; (3) determine the margin revenues by applying the weather-normalized test year consumption per customer to the "annualized" number of customers determined in step 2 and pricing the resulting kwh consumption out at current tariffs; and finally (4) comparing these annualized margin revenues determined in step 3 to the margin revenues reflected in the 12+0 test year, in total and by customer category.

Q. WHY DID YOU ASK THE COMPANY TO MAKE THESE REVENUE ANNUALIZATION CALCULATIONS?

A. I requested the Company to perform this test year-end customer growth revenue annualization analysis because I do not have the Company's detailed revenue model available and it would have been very difficult, if not impossible, for me to make these calculations with any degree of accuracy without the availability of the Company's sales and revenue model.

Q. WHAT IS THE RESULT OF THIS REVENUE ANNUALIZATION ANALYSIS FOR TEST YEAR-END CUSTOMER GROWTH AND HOW DOES THE REFLECTION OF SUCH ANNUALIZED REVENUES IMPACT

THE COMPANY'S PROPOSED PRO FORMA TEST YEAR OPERATING INCOME IN THIS CASE?

A. The response to RAR-A-103 shows that my recommended revenue annualization adjustment for customer growth up to the end of the test year increases the Company's proposed test year revenue margins by $3,704,000. As shown on Schedule RJH-9, this increases the Company's proposed pro forma test year operating income by approximately $2,186,000.

Q. HAS THE COMPANY CALCULATED AN ALTERNATIVE REVENUE ANNUALIZATION ADJUSTMENT FOR CUSTOMER GROWTH DURING THE TEST YEAR?

A. Yes, this alternative revenue annualization approach[3] for test year customer growth was calculated by the Company in its response to RAR-A-17. As shown in that response, this alternative revenue annualization approach for test year customer growth produces a revenue annualization adjustment of $8,440,702 rather than the revenue annualization adjustment of $3,704,000 that I recommend in this case. I have chosen not to reflect the higher revenue annualization adjustment because I believe that the calculation methodology underlying the recommended $3.7 million revenue annualization adjustment is superior to the alternative calculation methodology and is consistent with the calculation methodology used by me for similar adjustments in the Company's prior gas rate case and most recent electric rate case.

[3] This alternative revenue annualization approach is based on the comparison of the test year-end number of customers to the number of customers in each month of the test year.

- BPU/RPA Assessments

Q. WHAT IS THE ISSUE REGARDING THE COMPANY'S PROPOSED BPU/RPA ASSESSMENTS ADJUSTMENT IN THIS CASE?

A. As shown in Schedule RJH-10, in determining its proposed BPU/RPA assessments adjustment, the Company first calculated its proposed pro forma annualized assessment level of $6.611 million and then compared this pro forma expense to the actual test year BPU/RPA assessments. However, the Company has understated its actual test year assessment level. Specifically, while the Company has assumed an actual test year assessment level of $5.528 million, the response to RAR-A-34 confirms that the actual test year expense level is $5.896 million. As shown on Schedule RJH-10, the correction for this actual test year assessment understatement results in an increase in the Company's proposed pro forma test year operating income of $218,000.

- Incentive Compensation

Q. WHAT IS THE COMPANY'S PROPOSED POSITION IN THIS CASE WITH REGARD TO INCENTIVE COMPENSATION EXPENSES?

A. In this case, the Company is proposing to charge its ratepayers with approximately $3.4 million for incentive compensation expenses associated with the Long-Term Incentive Plan ("LTIP"), Management Incentive Compensation Plan ("MICP"), and

Performance Incentive Plan ("PIP").

Q. COULD YOU BRIEFLY DESCRIBE THESE THREE INCENTIVE COMPENSATION PROGRAMS?

A. Yes. The response to S-PREV-56 in PSE&G's prior gas rate case contains the following descriptions of these three incentive compensation plans:

> <u>Long-Term Incentive Plan (LTIP)</u>
> Participation in the LTIP is limited to officers and senior level associates. Stock options granted at fair market value are the primary vehicles used in the LTIP.
>
> <u>Management Incentive Compensation Plan (MICP)</u>
> MICP is considered a short-term annual incentive compensation plan for PSE&G officers as well as other officers throughout the Enterprise.[4] MICP is designed to motivate and reward officers for achievement of individual goals, business unit goals and overall company results. This plan, together with salary and benefit programs, is designed to provide overall compensation which is competitive. Individual officer incentive goals are based on a "balanced scorecard" approach in each participant's area of responsibility and relates to business plans, financial targets, customer service and other key objectives. A portion of an individual's award is influenced by overall corporate financial performance.
>
> <u>Performance Incentive Plan (PIP)</u>
> All PSE&G MAST associates participate in PIP. Similar to MICP, the Performance Incentive Plan is considered a short-term annual compensation plan. The overall objective of the program is to provide market based total compensation opportunity (salary plus incentive) that is competitive with similar positions found in other energy services organizations. Similar to MICP, awards are driven, in part, by overall corporate performance as well as business unit results which measure customer service/satisfaction, productivity, and employees safety.

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[4] The response to RAR-A-22 in the instant base rate case clarifies that the eligible participants of the MICP are "Vice Presidents and above."

Q. IS INCENTIVE COMPENSATION AWARDED TO THE ELIGIBLE RECIPIENTS IN ADDITION TO THEIR REGULAR BASE SALARY COMPENSATION?

A. Yes. The incentive compensation is being paid to the Company's officers, senior management and MAST[5] employees in addition to their current regular base salary compensation. In this regard, the PIP incentive program description states that:

> Your base salary rewards you for consistently performing the required responsibilities of your job. However, PIP rewards us collectively for our team efforts as well as individual contribution and *for stretching beyond what is required* and doing our part to help PSE&G create truly exceptional results. [emphasis supplied]

The above statement clearly indicates that the Company's incentive compensation programs represent *additive* employee compensation that is paid out in addition to the [base salary] compensation required to be paid to the employee for performing the job for which he/she was hired. Thus, the Company's incentive compensation expenses should be considered bonus compensation that is only paid out for "stretching beyond what is required" in order to achieve "truly exceptional results."

Q. WHAT HAVE BEEN THE RECENT ANNUAL INCREASES IN THE REGULAR BASE SALARIES OF PSE&G'S EXECUTIVE AND MAST EMPLOYEES WHO ALSO RECEIVE INCENTIVE COMPENSATION?

A. The response to RAR-A-24 indicates that the following wage/salary increases were received by PSE&G's Executive and MAST employees during the last 5 years:

	Executive	MAST

[5] MAST stands for Management, Administrative, Secretarial and Technical employees.

2001	4.4%	4.2 %
2002	4.0 %	4.0 %
2003	3.4 %	3.5 %
2004	3.4%	3.5%
2005	3.6%	3.5%

Q. DO THE PROPOSED TEST YEAR PRO FORMA WAGES AND SALARIES INCLUDE INCREASES FOR THE COMPANY'S EXECUTIVE AND MAST ASSOCIATES' REGULAR BASE SALARY COMPENSATION?

A. Yes. The Company has reflected salary increases of 3.5% effective April 2006 and has annualized the impact of these salary increases on the pro forma test year results.

Q. BASED ON THE PREVIOUSLY DISCUSSED INFORMATION, WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE RATE TREATMENT FOR THE LTIP, MCIP AND PIP INCENTIVE COMPENSATION EXPENSES PROPOSED BY THE COMPANY IN THIS CASE?

A. I recommend that the Company's proposed test year incentive compensation expenses of approximately $3.4 million be disallowed for rate making purposes in this case. As shown on Schedule RJH-11, my recommendation increases the Company's proposed pro forma test year operating income by approximately $2 million.

Q. WHAT ARE THE REASONS FOR THIS RECOMMENDATION?

First, for the LTIP, the criteria for determining the awards to be paid out under the plan are solely a function of corporate financial performance and are intended to more closely align the executive's interests with the long-term interest of PSEG shareholders. Similarly, for the MICP and PIP plans, the majority of an individual's awards payable under these plans are determined by the achievement of pre-determined overall corporate financial performance goals such as improvements in return on investment, return on equity and earnings per share. The shareholders of the parent corporation, PSEG, are the primary beneficiaries of such corporate financial performance improvements. For those reasons, PSEG's stockholders should be made responsible for these discretionary costs.

Second, the Company's recent (2001 - 2005) overall average wage and salary increases for executives and MAST associates have averaged close to 4% per year and the Company has proposed pro forma wage and salary increases of 3.5% in this case. Given the recently experienced and currently continuing low inflation rates, the Company's recent actual and proposed pro forma wage and salary increases would appear to be quite adequate. In my opinion, it would be excessive to have the ratepayers also fund the additive bonus incentive expenses claimed in this case.

Third, the Company has not presented evidence in this case showing the specific benefits that are accruing to the ratepayers as opposed to PSEG's shareholders as a result of these incentive compensation plans for which these same ratepayers are asked to pay 100% of the costs. Neither has the Company presented any evidence in this case showing that there is any appreciable difference in the productivity level of PSE&G's executives and MAST employees as a direct result of the incentive compensation paid out by the Company.

Q. DOES THE BOARD HAVE A STATED RATE MAKING POLICY WITH REGARD TO THE RATE TREATMENT OF INCENTIVE COMPENSATION?

A. Yes. In its Final Decision and Order in the Jersey Central Power & Light Company rate case, Docket No. 91121820J, dated February 25, 1993, the Board stated on page 4 of this Decision and Order:

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

Due to the current record high energy prices (among other things caused by the very high commodity costs of gas), the conditions in the instant PSE&G gas base rate proceeding are strikingly similar to the conditions surrounding the incentive compensation issue in the above-referenced JCP&L case. It is reasonable to assume that many of the Company's ratepayers are currently having trouble paying their utility bills which have recently increased dramatically as a result of the extraordinary high energy commodity costs. Furthermore, as discussed before, PSE&G's three incentive compensation programs are either fully or predominantly driven by the Company achieving financial performance goals for the benefit of shareholders of the parent corporation.

Q. DID THE BOARD REITERATE THIS INCENTIVE COMPENSATION RATE MAKING POLICY IN A MORE RECENT LITIGATED BASE RATE CASE?

A. Yes. In the recently completed fully-litigated 2001 Middlesex Water Company base rate case, the BPU Staff stated on page 37 of its Initial Brief with regard to Middlesex's incentive compensation expenses:

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

While the ALJ in that case ruled that 50% of Middlesex's incentive compensation expenses could be recovered in rates, the Board overruled the ALJ and ordered that 100% of these incentive compensation expenses be removed from Middlesex's rates.

- <u>Charitable Contributions</u>

Q. PLEASE EXPLAIN THE RECOMMENDED CHARITABLE CONTRIBUTION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-4, LINE 6.

A. The Company has proposed to include in its above-the-line test year operating expenses total charitable contribution expenses of $662,000 that, for book purposes, are recorded in the below-the-line expense Account 426. I have removed the entire $662,000 expense amount in accordance with the July 25, 2001 decision by the New Jersey Supreme Court which ruled that charitable contribution expenses incurred by a utility cannot be subsidized by consumers and, therefore, cannot be included as legitimate business expenses for rate making purposes.[6] In addition, these expenses should not be charged to PSE&G's captive ratepayers because the associated contributions have nothing whatsoever to do with the provision of safe, adequate and reliable gas service.

As shown on Schedule RJH-4, line 6, this recommended adjustment increases the Company's proposed pro forma test year operating income by $392,000.

- Institutional Advertising and Public Relations Expenses

Q. DOES THE BOARD HAVE A POLICY TO ELIMINATE FOR RATEMAKING PURPOSES ALL EXPENSES ASSOCIATED WITH

[6] *See In Re New Jersey American Water Co.*, 169 *N.J.* 181 (2001).

INSTITUTIONAL ADVERTISING AND PUBLIC RELATIONS EXPENSES?

A. Yes. This Board policy was first established almost 30 years ago in its 1977 and 1980 Orders in BPU Docket No. 7512-1254. In a more recent Jersey Central Power & Light Company rate case, Docket No. ER91121820J, the Board reiterated this advertising rate making policy on page 9 of its Order dated February 25, 1993 of that case:

> ...The Board policy concerning advertising expenditures is very clear and was set forth in its 1977 and 1980 Orders in Docket No. 7512-1254 regarding the rate making of utility advertising practices.
>
> Based upon the Board's advertising policy, the following expenses should be excluded from Petitioner's EEI allocation factor for the foregoing reasons:
>
> a. Legislative Advocacy, Regulatory Advocacy and Legislative Policy Research should be excluded because these categories meet the Board's definition of political advertising.
>
> b. Promotional advertising, Institutional advertising and Public relations expenditures should be excluded from the factor because these expenses were specifically excluded by the Board in its 1977 Order.

The Board again applied this policy in a recent Middlesex Water Company case, BPU Docket No. WR00060362. In that case, both the Ratepayer Advocate and Staff recommended the removal of certain public and community relations expenses from the test year. The Board adopted these recommendations, specifically referencing its ruling in Docket No. 7512-1254.

Q. IS THE COMPANY PROPOSING TO INCLUDE SUCH INSTITUTIONAL

ADVERTISING AND PUBLIC RELATIONS EXPENSES FOR RATEMAKING PURPOSES IN THIS CASE?

A. Yes. As shown on Schedule RJH-12, the Company's proposed test year expenses include a total expense amount of $525,000 for institutional and promotional advertising and public relations expenses.

The first and second items shown on Schedule RJH-12 concern promotional and branding advertising expenses. A review of the copies of the print ads and radio scripts for the promotional and branding advertising campaigns described in the response to RAR-A-29 clearly shows that this advertising represents institutional "goodwill" advertising.[7]

With regard to public relations expenses, the test year includes $238,000 for community affairs/public relations activities. From the response to RAR-A-27, one can see that these activities primarily consist of such items as volunteer recognition programs, community fund raising activities, the Power of Giving campaign, Tsunami disaster relief, and March of Dimes activities.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PREVIOUSLY DESCRIBED INSTITUTIONAL ADVERTISING AND PUBLIC RELATIONS EXPENSES?

A. I recommend that these expenses be removed for ratemaking purposes in this case

[7] PSEG's assistance in Hurricane Katrina; PSE&G receiving awards for outstanding service; PSE&G's efforts in volunteer programs and fundraisers; PSE&G as a protector of Mother Nature*, etc.*

as they are related to activities that have nothing to do with the provision of safe, adequate and reliable gas delivery service. The primary purpose of these expenses is the enhancement of PSEG's and PSE&G's image as good corporate citizens. These types of expenses should be the responsibility of the stockholders rather than the captive ratepayers. My recommendation is in accordance with long-standing and well-established Board policy. As shown on Schedule RJH-12, my recommendation to remove these expenses has the effect of increasing the Company's proposed pro forma test year operating income by $311,000.

- Merger Related Expenses

Q. HAVE YOU REMOVED ALL EXPENSES INCLUDED IN PSE&G'S PROPOSED TEST YEAR OPERATING EXPENSES THAT ARE RELATED TO THE PROPOSED PSEG/EXELON MERGER?

A. Yes. In response to SRR-43, the Company has confirmed that the test year includes $1.15 million for integration and retention expenses related to the proposed merger. These expenses must be removed from the test year for several reasons. First, as I discussed earlier in this testimony, the Company has filed this case under "business as usual" conditions that assume none of the merger-driven operational, structural and financial changes and net synergy savings that are currently being addressed in the pending merger proceeding in BPU Docket No. EM05020106. It is inappropriate and inconsistent to reflect merger related implementation expenses if no other aspects of the proposed merger are reflected in this case. Second, since these merger related expenses represent extraordinary, non-recurring expenses, they should not be included in test year expenses designed to be incurred by the Company on an ongoing annual basis. Finally, it is my understanding that it is the Ratepayer Advocate's stated position in the PSEG/Exelon merger case that merger related retention expense should be treated below-the-line for ratemaking purposes.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED PRO FORMA TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-13, my recommendation increases the Company's proposed pro forma test year operating income by $680,000.

- PSEG Enterprise Cost Allocations

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENTS REGARDING CERTAIN PSEG ENTERPRISE COSTS ALLOCATED TO PSE&G'S GAS OPERATIONS IN THE TEST YEAR.

A. As shown on Schedule RJH-14, line 6, I recommend that a total expense amount of $89,000 for PSEG Enterprise costs allocated to PSE&G gas be eliminated from the Company's proposed test year operating expenses. As shown on lines 1-3, these PSEG Enterprise expenses concern expenses for certain Enterprise membership fees, donations, and tickets to athletic events. These expenses are of no direct benefit to PSE&G's gas ratepayers and, therefore, should be moved below the line for ratemaking purposes in this case.

- <u>COLI Interest Expense</u>

Q. PLEASE EXPLAIN THE COLI INTEREST EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-15.

A. In its response to RAR-A-97, PSE&G confirms that the pro forma test year COLI interest expenses the Company has proposed to move above-the-line for ratemaking purposes in this case includes approximately $248,000 of interest expenses that were also included in the test year Account 923 expenses. The Company has agreed that this expense double-count should be removed from this case. I have done so on Schedule RJH-15. As shown on this schedule, the removal of this expense double-count increases the Company's proposed test year operating income by $147,000.

- <u>Western Union Customer Payment Center Expenses</u>

Q. PLEASE EXPLAIN THE WESTERN UNION CUSTOMER PAYMENT CENTER EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-16.

A. This concerns a pro forma test year expense adjustment that has been recommended by Mr. Kalcic and is explained in his testimony.

- <u>Miscellaneous O&M Expense Adjustment</u>

Q. PLEASE EXPLAIN THE MISCELLANEOUS EXPENSE ADJUSTMENTS YOU SHOW ON SCHEDULE RJH-17.

A. I recommend that a total expense amount of $498,000, consisting of 7 miscellaneous O&M expense adjustments, be removed for ratemaking purposes in this case. This recommendation has the effect of increasing the Company's proposed test year operating income by $295,000.

Q. PLEASE DESCRIBE EACH OF THESE RECOMMENDED MISCELLANEOUS O&M EXPENSE ADJUSTMENTS.

A. The expense adjustments on lines 1-4 concern lobbying, public relations and institutional advertising activities. For the reasons previously discussed, these expenses should be treated below-the-line for ratemaking purposes, in accordance with long-standing BPU ratemaking policy.

The fifth expense adjustment concerns the removal of all Electric Power Research Institute (EPRI) expenses that are included in the test year by PSE&G. As shown in the response to RAR-A-85, the Company's proposed test year expenses include a total of $173,000 for EPRI membership dues allocated to PSE&G's gas operations. I do not agree with the Company's position on this issue. EPRI is a national research organization established by the electric utility industry with the purpose of servicing that industry. It may be true that some of EPRI's research could be of some use to PSE&G's gas business. However, it may similarly be the case that the research conducted by national gas research organizations such as GTI is of some use to PSE&G's electric operations. However, none of the costs of the GTI R&D is allocated to PSE&G's electric operations. Based on these reasons, it is my recommendation that the membership dues and invoices paid by PSE&G to EPRI during the test year be assigned 100% to PSE&G's electric operations.

The sixth adjustment concerns the removal from the test year of estimated Club membership expenses. In RAR-A-77, the Ratepayer Advocate requested the Company to provide a listing and dollar breakout of all club membership expenses included in the above-the-line O&M expenses. In response the Company referred to its response to S-PREV-26 in which the same type of information was requested. However, in this latter response the Company states:

> Approvals and/or payments for individual dues or fees are made at a local department level. A breakdown or listing of such payments for club dues or membership fees, for individuals throughout the Company is not maintained in any one location and therefore is not available….

I am quite surprised that PSE&G, with all of its bountiful resources, is not able to track and provide this type of information. Based on my experience with other large utility companies, I have assumed that PSE&G's test year operating expenses include an estimated $10,000 worth of club membership dues. If PSE&G does not agree with this estimated expense, it should perform the required expense tracking and provide the actual test year expenses associated with such membership dues.

The final expense adjustment concerns the removal from the test year of expenses associated with the provision of certain financial services to PSE&G's top officers. As described in the response to RAR-A-23, these financial services include personal financial counseling and estate planning for PSE&G officers and other selected senior management personnel. I do not believe that the Company's ratepayers should be required to fund these types of top officers' compensation "perks". This should be the responsibility of the Company's shareholders.

- <u>Annualized Depreciation Expenses</u>

Q. IS THE COMPANY PROPOSING BASE RATE RECOGNITION FOR NEW DEPRECIATION RATES FOR ITS GAS PLANT IN THIS CASE?

A. Yes. As described on page 8 of Mr. Stellwag's direct testimony, the Company is seeking approval from the Board to implement "new gas distribution depreciation rates based on a Gas Depreciation Study, supported by the testimony of Mr. Earl M. Robinson…." The Company is also proposing to annualize its test year depreciation expenses by applying Mr. Robinson's recommended depreciation rates to the Company's test year-end 9/30/05 depreciable plant in service balances. As shown in columns 1-3 of Schedule RJH-18, this annualized depreciation approach results in PSE&G-proposed pro forma test year depreciation expenses amounting to approximately $168.5 million.

Q. DOES THE RATEPAYER ADVOCATE'S DEPRECIATION EXPERT,

MICHAEL MAJOROS, AGREE WITH THE COMPANY'S PROPOSED GAS DEPRECIATION RATES?

A. No. Mr. Majoros does not agree with the Company's proposed depreciation rates and has recommended appropriate alternative depreciation rates that should be approved by the BPU for rate making purposes in this case. Mr. Majoros has supplied me with his recommended depreciation rates and I have used these depreciation rates in the calculation of the recommended pro forma annualized depreciation expenses in this case.

Q. WHERE DO YOU SHOW THESE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSE CALCULATIONS?

A. These calculations are shown on Schedule RJH-18. As shown on line 5 of this schedule, Mr. Majoros' recommended depreciation rates produce a recommended level of pro forma annualized depreciation expenses of approximately $89.4 million based on the same level of test-year end depreciable plant as was used by the Company in its proposed pro forma depreciation expense adjustment calculations.

Q. WHAT IS THE IMPACT OF THE DIFFERENCE BETWEEN THE RATEPAYER ADVOCATE'S RECOMMENDED AND THE COMPANY'S PROPOSED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES?

A. As shown on Schedule RJH-18, lines 5-7, the Ratepayer Advocate's recommended pro forma annualized depreciation expense level of $89.4 million is $79.1 million lower than the Company's proposed pro forma annualized depreciation expense level of $168.5 million. This recommended expense reduction has the effect of increasing the Company's proposed pro forma test year operating income by approximately $51.4 million.

- Amortization of Cost of Removal Regulatory Liability

Q. HAVE YOU ADOPTED ANOTHER DEPRECIATION RELATED ADJUSTMENT RECOMMENDED BY MR. MAJOROS?

A. Yes. I have adopted Mr. Majoros' recommendation for a 3-year amortization of a Cost of Removal related regulatory liability balance. Mr. Majoros has determined that this regulatory liability balance amounts to $134.372 million and that a 3-year amortization of this balance would reduce his recommended annual depreciation expenses of $89.4 million by approximately $44.8 million. On Schedule RJH-18, lines 8–11, I show that this recommended $44.8 million depreciation expense reduction would increase the Company's pro forma test year operating income by approximately $26.5 million.

- Income Taxes and Interest Synchronization Adjustment

Q. WHAT ARE THE UNADJUSTED PER BOOKS CURRENT FEDERAL AND STATE INCOME TAXES INCLUDED IN THE OPERATING EXPENSES FOR THE TEST YEAR?

A. As shown on Schedule ANS-17 R-1, lines 2 and 3, the unadjusted per books test year operating expenses include a combined total of $36.855 million for current federal and state income taxes.

Q. WHAT IS THE TOTAL TEST YEAR UNADJUSTED PER BOOKS GAS INTEREST EXPENSE AMOUNT THAT WAS USED AS A TAX DEDUCTION IN THE CALCULATION OF THE TEST YEAR'S UNADJUSTED PER BOOKS CURRENT FEDERAL AND STATE INCOME TAXES OF $36.855 MILLION?

A. The Company was asked this exact question in RAR-A-15(b) and responded that the test year per books gas interest expenses used as a tax deduction in the determination of the test year's current federal and state income taxes of $36.855 million amounts to $55.340 million.

Q. HAS THE COMPANY USED THIS TEST YEAR UNADJUSTED PER BOOKS GAS INTEREST AMOUNT OF $55.340 MILLION IN ITS PROPOSED INTEREST SYNCHRONIZATION ADJUSTMENT IN SCHEDULE ANS-23 R-1?

A. No. In the determination of its proposed interest synchronization adjustment, the Company compared its pro forma synchronized interest expense amount (determined by applying its proposed weighted cost of debt in the overall rate of return to its proposed rate base) to an "adjusted test year interest" amount of $61.284 million rather than to the test year per books gas interest expense amount of $55.340 million that was actually used as tax-deductible interest in the determination of the test year's current federal and state income taxes of $36.855 million. This must be corrected as it results in an incorrect interest synchronization adjustment.

Q. COULD YOU EXPLAIN THIS IN MORE DETAIL?

A. Yes. Under the assumption that the test year tax-deductible interest expenses in the determination of the test year current and federal and state income taxes amounted to $61.284 million rather than the actual amount of $55.340 million, the test year's unadjusted per books current federal and state income taxes of $36.855 would be $2.428 million[8] lower, or $34.427 million. However, while the Company assumed test year tax-deductible interest expenses of $61.284 rather than $55.340 million in its proposed interest synchronization adjustment (which increased its pro forma current income taxes by $2.428 million), it did not at the same time reduce the test year's unadjusted per books current federal and state income taxes of $36.855 million on ANS-17 R-1 by $2.428 million to $34.427 million. This income tax double-count in the Company's proposed pro forma income tax determination must be rejected by the Board.

Q. HAVE YOU USED THE CORRECT APPROACH IN THE DETERMINATION OF THE RECOMMENDED INTEREST SYNCHRONIZATION ADJUSTMENT SHOWN ON SCHEDULE RJH-19?

[8] A tax-deductible interest expense of $61.284 rather than $55.340 would result in an additional tax deduction of $5.944 million which, when multiplied by the composite income tax rate of 40.85%, would result in a reduction of current income taxes of $2.428 million.

A. Yes. The purpose of an interest synchronization adjustment is to "synchronize" the interest expenses to be used as a tax deduction in the determination of the test year current federal and state income taxes with the debt interest that is implicit in the allowed overall rate of return used for ratemaking purposes. The so-determined "pro forma" interest expense amount must then be compared to the test year interest expense amount that was actually used as a tax deduction in the determination of the test year current federal and state income taxes in order to calculate the appropriate income tax impact of the interest synchronization adjustment. I have properly done so on Schedule RJH-19.

Q. ARE THERE ANY OTHER REASONS THAT HAVE CAUSED A DIFFERENCE BETWEEN THE COMPANY'S PROPOSED AND YOUR RECOMMENDED INTEREST SYNCHRONIZATION ADJUSTMENTS?

A. Yes. The Company's proposed and my recommended interest synchronization adjustments are also different because the Company's proposed and my recommended rate base and weighted cost of debt positions are different.

Q. MR. HENKES DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPENDIX I

<u>PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES</u>

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company Report Re. PROMOD and Its Use in	Docket 85-26	10/1986

Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001
Chesapeake Gas Company	Docket No. 01-307	12/2001

Gas Base Rate Proceeding*		
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984

Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996
Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998

Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005

FERC

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

KENTUCKY

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997
Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999
Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999
Louisville Gas & Electric Company	Case No. 2000-080	06/2000

Gas Base Rate Proceeding*		
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2005-00042	06/2005
Big Sandy Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00125	08/2005
Louisville Gas & Electric Company Value Delivery Surcredit Mechanism*	Case No. 2005-00352	12/2005
Kentucky Utilities Company	Case No. 2005-00351	12/2005

Value Delivery Surcredit Mechanism*		
Kentucky Power Company Electric Base Rate Proceeding*	Case No. 2005-00341	01/2006
Cumberland Valley Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00187	05/2006

MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine Chapter 120 Earnings Review	Docket 94-254	12/1994

MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982

Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982
Chesapeake and Potomac Telephone Company Divestiture Base Rate Proceeding*	Case 7735	10/1983
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

<u>NEW HAMPSHIRE</u>

Granite State Electric Company Electric Base Rate Proceeding	Docket DR 77-63	1977

<u>NEW JERSEY</u>

Elizabethtown Water Company Water Base Rate Proceeding	Docket 757-769	07/1975
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976
Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977

Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979
Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 849-1014	11/1984
AT&T Communications of New Jersey	Docket 8311-1064	05/1985

Base Rate Proceeding*		
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey Base Rate Proceeding	Docket TR8810-1187	08/1989
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER92090900J	12/1992
Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993

Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER91111698J	03/1993
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER 94070293	11/1994
Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995
Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER95090425	01/1996
United Water of New Jersey Base Rate Proceeding*	Docket WR95070303	01/1996
Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996

New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company Base Rate Proceeding*	Docket WR96030204	07/1996
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996
Public Service Electric & Gas Company and Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	Docket Nos. ES96039158 & ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No.WR96100768	03/1997
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No.ER97080562	12/1997
Rockland Electric Company Limited Issue Rate Proceeding	Docket No.ER97080567	12/1997
South Jersey Gas Company Limited Issue Rate Proceeding	Docket No.GR97050349	12/1997

New Jersey American Water Company Limited Issue Rate Proceeding	Docket No.WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company Limited Issue Rate Proceedings	Docket Nos. WR97040288, WR97040289	12/1997
United Water of New Jersey, United Water Toms River and United Water Lambertville Limited Issue Rate Proceedings	Docket Nos.WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998
New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998
Consumers New Jersey Water Company Merger Proceeding	Docket No.WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No.WR98090795	03/1999
Mount Holly Water Company Base Rate Proceeding - Phase I*	Docket No. WR99010032	07/1999
Mount Holly Water Company Base Rate Proceeding - Phase II*	Docket No. WR99010032	09/1999
New Jersey American Water Company Acquisitions of Water Systems	Docket Nos. WM9910018 WM9910019	09/1999 09/1999
Mount Holly Water Company Merger with Homestead Water Utility	Docket No. WM99020091	10/1999
Applied Wastewater Management, Inc. Merger with Homestead Treatment Utility	Docket No.WM99020090	10/1999
Environmental Disposal Corporation (Sewer)	Docket No.WR99040249	02/2000

Base Rate Proceeding*

Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No.GR99070509	03/2000
DSM Adjustment Clause Proceeding	Docket No. GR99070510	03/2000
New Jersey American Water Company Gain on Sale of Land	Docket No. WM99090677	04/2000
Jersey Central Power & Light Company NUG Contract Buydown	Docket No. EM99120958	04/2000
Shore Water Company Base Rate Proceeding	Docket No. WR99090678	05/2000
Shorelands Water Company Water Diversion Rights Acquisition	Docket No. WO00030183	05/2000
Mount Holly and Elizabethtown Water Companies	Docket Nos. WO99040259	06/2000
Computer and Billing Services Contracts	WO9904260	06/2000
United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
E'Town Corporation Merger with Thames, Ltd.	Docket No. WM99120923	08/2000
Consumers Water Company Water Base Rate Proceeding*	Docket No. WR00030174	09/2000
Atlantic City Electric Company Buydown of Purchased Power Contract	Docket No. EE00060388	09/2000
Applied Wastewater Management, Inc. Authorization for Accounting Changes	Docket No. WR00010055	10/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No. GR00070470	10/2000
DSM Adjustment Clause Proceeding	Docket No. GR00070471	10/2000
Trenton Water Works Water Base Rate Proceeding*	Docket No. WR00020096	10/2000
Middlesex Water Company Water Base Rate Proceeding*	Docket No. WR00060362	11/2000

New Jersey American Water Company Land Sale - Ocean City	Docket No. WM00060389	11/2000
Pineland Water Company Water Base Rate Proceeding*	Docket No. WR00070454	12/2000
Pineland Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR00070455	12/2000
Elizabethtown Gas Company Regulatory Treatment of Gain on Sale of Property*	Docket No. GR00070470	02/2001
Wildwood Water Utility Water Base Rate Proceeding*	Docket No. WR00100717	04/2001
Roxbury Water Company Water Base Rate Proceeding	Docket No. WR01010006	06/2001
SB Water Company Water Base Rate Proceeding	Docket No. WR01040232	06/2001
Pennsgrove Water Company Water Base Rate Proceeding*	Docket No. WR00120939	07/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Direct Testimony	Docket No. GR01050328	08/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Surrebuttal Testimony	Docket No. GR01050328	09/2001
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR01040205	10/2001
Middlesex Water Company Financing Proceeding	Docket No. WF01090574	12/2001
New Jersey American Water Company Financing Proceeding	Docket No. WF01050337	12/2001
Consumers New Jersey Water Company Stock Transfer/Change in Control Proceeding	Docket No. WF01080523	01/2002
Consumers New Jersey Water Company	Docket No. WR02030133	07/2002

Water Base Rate Proceeding

New Jersey American Water Company — Docket No. WM01120833 — 07/2002
Change of Control (Merger) Proceeding*

Borough of Haledon – Water Department — Docket No. WR01080532 — 07/2002
Water Base Rate Proceeding*

New Jersey American Water Company — Docket No. WM02020072 — 09/2002
Change of Control (Merger) Proceeding

Public Service Electric & Gas Company — Docket No. ER02050303 — 10/2002
Electric Base Rate Proceeding
Direct Testimony*

United Water Lambertville — Docket No. WM02080520 — 11/2002
Land Sale Proceeding

United Water Vernon Hills & Hampton — Docket No. WE02080528 — 11/2002
Management Service Agreement

United Water New Jersey — Docket No. WO02080536 — 12/2002
Metering Contract With Affiliate

Public Service Electric & Gas Company — Docket No. ER02050303 — 12/2002
Electric Base Rate Proceeding
Surrebuttal and Supplemental Surrebuttal Testimonies*

Public Service Electric & Gas Company — Docket No. EO02110853 — 12/2002
Minimum Pension Liability Proceeding

Public Service Electric & Gas Company — Docket No. ER02050303 — 12/2002
Electric Base Rate Proceeding
Supplemental Direct Testimony*

Public Service Electric & Gas Company — Docket No. ER02050303 — 01/2003
Electric Deferred Balance Proceeding
Direct Testimony*

Rockland Electric Company — Docket No. ER02100724 — 01/2003
Electric Base Rate Proceeding
Direct Testimony*

Public Service Electric & Gas Company — Docket No. ER02050303 — 02/2003
Supplemental Direct Testimony*

Rockland Electric Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02100724	02/2003
Consumers New Jersey Water Company Acquisition of Maxim Sewerage Company	Docket No. WM02110808	05/2003
Rockland Electric Company Audit of Competitive Services	Docket No. EA02020098	06/2003
New Jersey Natural Gas Company Audit of Competitive Services	Docket No. GA02020100	06/2003
Public Service Electric & Gas Company Audit of Competitive Services	Docket No. EA02020097	06/2003
Mount Holly Water Company Water Base Rate Proceeding*	Docket No. WR03070509	12/2003
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR03070510	12/2003
New Jersey-American Water Company Water and Sewer Base Rate Proceeding*	Docket No. WR03070511	12/2003
Applied Wastewater Management, Inc. Water and Sewer Base Rate Proceeding*	Docket No. WR03030222	01/2004
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR03110900	04/2004
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2004
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR04060454	08/2004
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET04040235	08/2004
Wildwood Water Utility Water Base Rate Proceeding - Interim Rates	Docket No. WR04070620	08/2004
United Water Toms River Litigation Cost Accounting Proceeding	Docket No. WF04070603	11/2004

Lake Valley Water Company Water Base Rate Proceeding	Docket No. WR04070722	12/2004
Public Service Electric & Gas Company Customer Account System Proceeding	Docket No. EE04070718	02/2005
Jersey Central Power and Light Company Various Land Sales Proceedings	Docket No. EM04101107 Docket No. EM04101073 Docket No. EM04111473	02/2005 02/2005 03/2005
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR040080760	05/2005
Universal Service Fund Compliance Filing For 7 New Jersey Electric and Gas Utilities	Docket No. EX00020091	05/2005
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET05040313	08/2005
Public Service Electric & Gas Company Buried Underground Distribution Tariff Proceeding	Docket No. ET05010053	08/2005
Aqua New Jersey Acquisition of Berkeley Water Co. Water Merger Proceeding	Docket No. WM04121767	08/2005
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR05050451	10/2005
Public Service Electric & Gas Company Land Sale Proceeding	Docket No. EM05070650	10/2005
Public Service Electric & Gas Company Merger of PSEG and Exelon Corporation Direct Testimony	Docket No. EM05020106	11/2005
Public Service Electric & Gas Company* Merger of PSEG and Exelon Corporation Surrebuttal Testimony	Docket No. EM05020106	12/2005
Public Service Electric & Gas Company* Financial Review of Electric Operations	Docket No. ER02050303	12/2005
Rockland Electric Company Competitive Services Audit	Docket No. EA02020098	12/2005
Public Service Electric & Gas Company	Docket No. EE04070718	01/2006

Customer Accounting System Cost Recovery		
Roxiticus Water Company Stock Sale and Change of Ownership and Control	Docket No. WM05080755	01/2006
Public Service Electric & Gas Company Competitive Services Audit	Docket No. EA02020097	02/2006
Wildwood Water Company Water Base Rate Proceeding	Docket No. WR05070613	03/2006
Pinelands Water Company Water Base Rate Proceeding*	Docket No. WR05080681	03/2006
Pinelands Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR05080680	03/2006
Aqua New Jersey Company Water Base Rate Proceeding*	Docket No. WR05121022	06/2006

<u>NEW MEXICO</u>

Southwestern Public Service Company Electric Base Rate Proceeding*	Case 1957	11/1985
El Paso Electric Company Rate Moderation Plan	Case 2009	1986
El Paso Electric Company Electric Base Rate Proceeding	Case 2092	06/1987
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2147	03/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2162	06/1988
Public Service Company of New Mexico Phase-In Plan*	Case 2146/Phase II	10/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2279	11/1989
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2307	04/1990

El Paso Electric Company Rate Moderation Plan*	Case 2222	04/1990
Generic Electric Fuel Clause - New Mexico Amendments to NMPSC Rule 550	Case 2360	02/1991
Southwestern Public Service Company Rate Reduction Proceeding	Case 2573	03/1994
El Paso Electric Company Base Rate Proceeding	Case 2722	02/1998

OHIO

Dayton Power and Light Company Electric Base Rate Proceeding	Case 76-823	1976

PENNSYLVANIA

Duquesne Light Company Electric Base Rate Proceeding*	R.I.D. No. R-821945	09/1982
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	04/1984
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	11/1984
National Fuel Gas Distribution Company Gas Base Rate Proceeding*	Docket R-870719	12/1987

RHODE ISLAND

Blackstone Valley Electric Company Electric Base Rate Proceeding	Docket No. 1289	
Newport Electric Company Report on Emergency Relief		

VERMONT

Continental Telephone Company of Vermont Base Rate Proceeding	Docket No. 3986	
Green Mountain Power Corporation Electric Base Rate Proceeding	Docket No. 5695	01/1994
Central Vermont Public Service Corp. Rate Investigation	Docket No. 5701	04/1994
Central Vermont Public Service Corp. Electric Base Rate Proceeding*	Docket No. 5724	05/1994
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5780	01/1995
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5857	01/1996

VIRGIN ISLANDS

Virgin Islands Telephone Corporation Base Rate Proceeding*	Docket 126	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY - GAS RATE CASE
REVENUE REQUIREMENT
($000)

	PSE&G (12+0) (1)	Adjustment	RPA	
1. Rate Base	$ 1,952,841	$ (181,874)	$ 1,770,967	Sch. RJH-3
2. Rate of Return	8.51%		7.66%	Sch. RJH-2
3. Operating Income Requirement	166,187		135,606	
4. Pro Forma Operating Income	85,422	91,647	177,069	Sch. RJH-4
5. Operating Income Deficiency	80,765		(41,463)	
6. Revenue Conversion Factor	1.6946		1.6946	
7. Revenue Requirement	$ 136,864	$ (207,128)	$ (70,264)	

(1) Schedule ANS-1 R-1

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
RATE OF RETURN
($000)

	Capital Structure Ratios	Cost Rates	Weighted Cost Rates
PSE&G POSITION (1):			
Long Term Debt	47.98%	6.09%	2.92%
Preferred Stock	1.34%	5.03%	0.07%
Customer Deposits	0.72%	2.94%	0.02%
Common Equity	49.96%	11.00%	5.50%
Total Capital	100.00%		8.51%
RPA POSITION (2):			
Long Term Debt	49.52%	6.19%	3.07%
Short Term Debt	2.22%	4.80%	0.11%
Preferred Stock	1.24%	5.03%	0.06%
Customer Deposits	0.67%	2.94%	0.02%
Common Equity	46.35%	9.50%	4.40%
Total Capital	100.00%		7.66%

(1) Schedule ANS-37 R-1
(2) Testimony of Matthew Kahal, Schedule MIK-1

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
RATE BASE
($000)

	PSE&G (12+0) (1)	Adjustment	RPA	
1. Utility Plant In Service	$ 3,991,048		$ 3,991,048	
2. Accumulated Depreciation	(1,830,564)	61,928	(1,768,636)	Sch. RJH-5
3. Customer Advances	(1,474)		(1,474)	
4. Working Capital:				
a. Lead/Lag Study Cash	154,455	(47,847)	106,608	Sch. RJH-6
b. Net Assets and Liabilities	(1,057)		(1,057)	
c. Materials and Supplies	11,705		11,705	
d. Prepayments	4,105		4,105	
e. Total Net Working Capital	169,208	(47,847)	121,361	
5. Deferred Income Taxes	(375,378)	(13,523)	(388,901)	Sch. RJH-7
6. Consolidated Income Tax Benefits	-	(182,431)	(182,431)	Sch. RJH-8
7. TOTAL NET RATE BASE	$ 1,952,840	$ (181,873)	$ 1,770,967	

(1) Schedules ANS-2 R-1and MPM-1 R-1

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
PRO FORMA OPERATING INCOME
($000)

1. Pro Forma Utility Operating Income Proposed by PSE&G:	$ 85,422	(1)
RPA Recommended Adjustments:		
2. Remove Price Elasticity Adjustment	5,557	(2)
3. Test Year-End Customer Revenue Annualization Adjustment	2,186	Sch. RJH-9
4. Correct BPU/RPA Assessments Adjustment	218	Sch. RJH-10
5. Remove Incentive Compensation Expense	2,025	Sch. RJH-11
6. Remove Charitable Contribution Expenses	392	(3)
7. Remove Institutional Advertising and Public Relations Expenses	311	Sch. RJH-12
8. Remove Merger Related Expenses	680	Sch. RJH-13
9. Remove PSEG Enterprise Cost Allocations	53	Sch. RJH-14
10. Remove COLI Interest Double-Count	147	Sch. RJH-15
11. Add Western Union Customer Payment Center Expenses	(139)	Sch. RJH-16
12. Miscellaneous O&M Expense Adjustments	295	Sch. RJH-17
13. Annualized Depreciation Expense Adjustment	51,392	Sch. RJH-18
14. Amortization of Cost of Removal Regulatory Liability	26,494	Sch. RJH-18
15. Interest Synchronization Adjustment	2,037	Sch. RJH-19
16. Pro Forma Utility Operating Income Recommmended by RPA	$ 177,069	

(1) Schedule ANS-19 R-1, page 2
(2) Schedule ANS-36 R-1
(3) Schedule ANS-29 R-1

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
ACCUMULATED DEPRECIATION
($000)

	PSE&G (12+0) (1)	Adjustment	RPA	
1. Actual 9/30/05 Accumulated Depreciation Balance	$ (1,806,014)		$ (1,806,014)	
2. Annualized Depreciation Expense In Excess of Test Year Depreciation	(49,100)	123,857	74,757	(2)
3. Impact of Line 2 on Pro Forma Depreciation Reserve (L2 x 50%)	(24,550)	61,928	37,378	
4. Pro Forma Depreciation Reserve Balance (L1 + L3)	$ (1,830,564)	$ 61,928	$ (1,768,636)	

(1) Schedule ANS-4 R-1
(2) Recommended annualized depreciation expense, net of

amortization of C.O.R Regulatory Liability	$ 44,616	Sch. RJH-18, L5 - L9
Less: Per books test year depreciation expense	119,373	Sch. ANS-20 R-1
	$ (74,757)	

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
RECOMMENDED LEAD/LAG STUDY CASH WORKING CAPITAL
($000)

	I	II	III		IV		V
	PSE&G (12+0)	Adjustment	RPA		Lag Days		Weighted Amount
	(1)		[I+II]		(1)		[IIIxIV]
1. Total Revenue Lag					47.00		
Expenses and Taxes:							
2. Gas Supply Cost	$ 2,086,756		$ 2,086,756		35.10		$ 73,245,136
3. Salary & Wages	264,519		264,519		15.20		4,020,689
4. Pensions & Benefits	61,225		61,225		2.00		122,450
5. Uncollectibles	30,624		30,624		155.80		4,771,219
6. Other O&M	61,948		61,948		18.30		1,133,648
7. Depreciation	145,702	(145,702)	-		-		-
8. Current FIT	27,590		27,590		37.00		1,020,830
9. Current SIT	13,954		13,954		(90.00)		(1,255,860)
10. Deferred Income Taxes	24,741	(24,741)	-		-		-
11. Taxes o/t Income Taxes	61,355		61,355		(31.60)		(1,938,818)
12. Return on Capital	142,619	(142,619)	-		-		-
13. Long Term Debt Interest	-	57,478	57,478	(2)	91.25	(3)	5,244,868
14. Total Expense Lag	$ 2,921,033	$ (255,584)	$ 2,665,449		32.40		$ 86,364,162
15. Net Lag Days:							
Revenue Lag Days					47.00		
Expense Lag Days					32.40		
Net Lag Days					14.60		
16. Average Daily Expense (Col. III, Line 14 / 365)					$ 7,303		
17. Lead/Lag Study Cash Working Capital					$ 106,608		

(1) Schedule MPM-2 R-1
(2) Schedule RJH-19, Line 3
(3) Semi-Annual payment is 365 / 2 = 182.5 days. Average lag period is 182.5 / 2 = 91.25 days

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
ACCUMULATED DEFERRED INCOME TAXES
($000)

	PSE&G (12+0) (1)	Adjustment	RPA	
1. Liberalized Depreciation	$ (366,966)		$ (366,966)	
2. Cost of Removal	(5,541)		(5,541)	
3. Computer Software	(1,121)		(1,121)	
4. Capitalized Interest	536		536	
5. NJ Corporate Business Tax	(10,878)		(10,878)	
6. Depreciation Study Impact	8,593	(8,593)	-	
7. Loss on Reacquired Debt	-	(4,931)	(4,931)	(2)
8. Total Pro Forma ADIT Balance	$ (375,377)	$ (13,524)	$ (388,901)	

(1) Schedule ANS-8 R-1
(2) Filing workpaper page 22

BPU Docket No. GR05100845
Test Year: 9/30/05

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
CONSOLIDATED INCOME TAX BENEFITS
($000)

	Taxable Income/(Loss)								
	Total PSEG	Regulated PSE&G	Non-Regulated PSEG Subsidiaries	Tax Rate	Tax Benefits Assigned to PSE&G	AMT Payments	Tax Benefits Assigned to PSE&G Net of AMT	PSE&G's Gas Tax Ratio	Net Tax Benefits Assigned to PSE&G - Gas
	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	
1991	$ 224,033	$ 538,385	$ (314,352)	34%	(106,880)	56,008	(50,872)	7.09%	(3,607)
1992	407,870	639,247	(231,377)	34%	(78,668)	10,132	(68,536)	24.49%	(16,785)
1993	258,029	427,471	(169,442)	35%	(59,305)	37,331	(21,974)	-4.34%	954
1994	475,837	708,507	(232,670)	35%	(81,435)	-	(81,435)	26.07%	(21,230)
1995	595,683	699,501	(103,818)	35%	(36,336)	-	(36,336)	17.02%	(6,184)
1996	806,927	684,439	122,488	35%	42,871	-	42,871	12.68%	5,436
1997	727,552	836,047	(108,495)	35%	(37,973)	-	(37,973)	17.25%	(6,550)
1998	928,306	963,748	(35,442)	35%	(12,405)	-	(12,405)	7.40%	(918)
1999	1,118,680	523,535	595,146	35%	208,301	-	208,301	25.57%	53,263
2000	395,508	467,340	(71,832)	35%	(25,141)	-	(25,141)	19.92%	(5,008)
2001	355,336	314,963	40,373	35%	14,131	-	14,131	-35.36%	(4,997)
2002	55,044	106,752	(51,708)	35%	(18,098)	-	(18,098)	10.06%	(1,821)
2003	(211,073)	252,199	(463,272)	35%	(162,145)	-	(162,145)	79.11%	(128,273)
2004	306,838	628,220	(321,382)	35%	(112,484)	-	(112,484)	18.26%	(20,540)
2005	211,028	764,105	(553,077)	35%	(193,577)	-	(193,577)	13.52%	(26,172)
Total									$ (182,431)

(1) Response to RAR-A-35 in prior PSE&G gas rate case for 1991-2000.
Response to RAR-A-12 in current case for 2001-2005.

(2) Response to RAR-A-13

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
TEST YEAR-END CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT
($000)

1.	Difference Between PSE&G's Proposed 12+0 Test Year Revenue Margins and Recommended Revenue Margins Based on the Annualization of Customer Growth Through the End of the Test Year, September 30, 2005	$ 3,704	(1)
2.	Less: BPU Assessments @ .1985%	(7)	
	RPA Assessments @ .0359%	(1)	
3.	Net Revenue Margin Increase Prior to Income Taxes	3,695	
4.	Income Tax Impact @ 40.85%	(1,510)	
5.	Recommended Increase in Operating Income	$ 2,186	

(1) Response to RAR-A-103

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
BPU and RPA ASSESSMENTS
($000)

	PSE&G (12+0) (1)	Adjustment	RPA	
1. Pro Forma BPU/RPA Assessments	$ 6,611		$ 6,611	
2. Assessments Included in Test Year Operating Expense	5,528	368	5,896	(2)
3. Operating Expense Adjustment	$ 1,083	(368)	$ 715	
4. Income Tax Impact @ 40.85%		150		
5. Recommended Increase in Operating Income		$ 218		

(1) Schedule ANS-27 R-1
(2) Schedule ANS-14 R-1, line 14 and response to RAR-A-34

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
INCENTIVE COMPENSATION
($000)

	PSE&G (12+0) (1)	Adjustment	RPA
1. Officers' and Top Management Incentive Compensation (LTIP & MICP)	$ 524	$ (524)	$ -
2. MAST Employees' Incentive Compensation (PIP)	2,900	(2,900)	-
3. Total LTIP, MICP and PIP	$ 3,424	(3,424)	$ -
4. Income Tax Impact @ 40.85%		1,399	
5. Recommended Increase in Operating Income		$ 2,025	

(1) Response to RAR-A-22

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
INSTITUTIONAL ADVERTISING AND PUBLIC RELATIONS EXPENSE ADJUSTMENTS
($000)

1. Remove Acct 923 - Promotional Advertising	$	(177)	(1)
2. Remove Acct 923 - Branding Campaign		(110)	(1)
3. Remove Community Affairs/Public Relations Exp. in Accts 920 and 923		(238)	(2)
4. Total Recommended Expense Removal	$	(525)	
5. Income Tax Impact @ 40.85%		214	
6. Recommended Increase in Operating Income	$	311	

(1) Response to RAR-A-29
(2) Response to RAR-A-27

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
MERGER RELATED COSTS
($000)

1. Remove Merger Related Integration and Retention Expenses Included in Test Year	$	(1,150)	(1)
2. Income Tax Impact @ 40.85%		470	
3. Recommended Increase in Operating Income	$	680	

(1) Response to SRR-43

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
PSEG ENTERPRISE COST ALLOCATIONS
($000)

1.	Remove Costs for Bowling Tournament, Continental Arena Tickets and NJPAC Season Tickets	$ (233)	(1)
2.	Remove Membeship Fees	(25)	(2)
3.	Remove Donation Expenses	(154)	(1)
4.	Total Expense Removal	(412)	
5.	Allocation Factor for Gas Utility Share	21.61%	
6.	PSE&G Gas-Allocated Expense Removal	(89)	
7.	Income Tax Impact @ 40.85%	36	
8.	Recommended Increase in Operating Income	$ 53	

(1) Response to RAR-A-79
(2) Response to RAR-A-79: The Conference Board; Two Hundred Club of Essex; Council on Foundations; Public Affairs Council

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
COLI INTEREST EXPENSE ADJUSTMENT
($000)

1. Remove Double-Counted COLI Interest Expense	$	(248)	(1)
2. Income Tax Impact @ 40.85%		101	
3. Recommended Increase in Operating Income	$	147	

(1) Response to RAR-A-97
(2) Response to RAR-A-27

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
WESTERN UNION CUSTOMER PAYMENT CENTER EXPENSES
($000)

1. Test Year Pro Forma Expense Increase for Western Union Customer Payment Center	$	235	(1)
2. Income Tax Impact @ 40.85%		(96)	
3. Recommended Decrease in Operating Income	$	(139)	

(1) Recommended by Mr. Kalcic per response to RAR-RD-18.
(2) Response to RAR-A-27

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
MISCELLANEOUS EXPENSE ADJUSTMENTS
($000)

1. Remove AGA Lobbying, Public Relations, and Institutional Advertising Expenses	$	(106)	(1)
2. Remove NJUA Lobbying Expenses		(4)	(2)
3. Remove Outside Services Lobbying Fees		(168)	(3)
4. Remove Lobbying Payroll and Fringes		(12)	(4)
5. Remove EPRI Membership Dues Allocated to Gas Operations		(173)	(5)
6. Remove Club Membership Expenses		(10)	
7. Remove Counseling and Estate Planning Expenses		(25)	(6)
8. Total Expense Removal		(498)	
9. Income Tax Impact @ 40.85%		203	
10. Recommended Increase in Operating Income	$	295	

(1) Per response to RAR-A-78:

- Test year AGA dues of $460,372 x 16% (lobbying %) =	$	73,660
- Test year AGA dues of $460,372 x 5% (Public Rel. %) =		23,019
- Test year AGA dues of $460,372 x 2% (Instit. Advertising %) =		9,207
	$	105,886

(2) Per response to RAR-A-78:

- Test year NJUA dues of $26,044 x 16% (lobbying %) =	$	4,167

(3) Response to RAR-A-96
(4) Responses to RAR-A-86 and S-PREV-24
(5) Response to RAR-A-85, page 2
(6) Response to RAR-A-23

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
PRO FORMA DEPRECIATION EXPENSES
($000)

	1	2	3	4	5
	12+0 Plant 9/30/05	PSE&G Proposed Rates	PSE&G Annualized Expense	RPA Recommended Rates	RPA Annualized Expense
DEPRECIATION ACCRUAL:	(1)		(1)	(2)	(2)
1. Gas Plant - Depreciable:					
a. Production	$ 45,935	3.73%	$ 1,713	2.87%	$ 1,318
b. Storage	9,107	4.02%	366	2.92%	266
c. Transmission Mains	62,909	2.54%	1,598	2.16%	1,359
d. Transmission Str. & Impr.	395	2.35%	9	2.28%	9
e. Transmission Meas. & Reg.	6,299	5.06%	319	4.92%	310
f. Distribution	3,578,643	3.97%	142,072	1.61%	57,616
g. Total Depreciable Gas Plant	3,703,288				
h. Normalized Net Salvage Allow.			0		6,135
2. Gas Plant - Non-Depreciable	10,463		0		0
3. Gas General & Intangible Plant	160,059		19,214		19,214
4. Gas Common Plant	117,238		3,181		3,180
5. Total	$ 3,991,048		$ 168,473	(79,065)	$ 89,407
6. Income Tax Impact @ 35% (3)				27,673	
7. Recommended Increase in Operating Income				$ 51,392	

AMORTIZATION OF C.O.R.
REGULATORY LIABILITY:

8. Total Regulatory Liability	$ 134,372	(2)
9. 3-Year Amortization of Regulatory Liability	44,791	(2)
10. Income Tax Impact @ 40.85%	18,297	
11. Recommended Increase in Operating Income [L9 - L10]	$ 26,494	

(1) RAR-DEP-120, pages 6-7
(2) Testimony of Michael Majoros
(3) Schedule ANS-20 R-1

PUBLIC SERVICE ELECTRIC GAS COMPANY - GAS RATE CASE
INTEREST SYNCHRONIZATION ADJUSTMENT
($000)

	PSE&G (12+0) (1)	Adjustment	RPA	
1. Rate Base	$ 1,952,840	$ (181,873)	$ 1,770,967	Sch. RJH-3
2. Weighted Cost of Debt	2.94%		3.19%	Sch. RJH-2
3. Pro Forma Interest	57,478	(957)	56,521	
4. Less: Test Year Interest	61,284		55,340	(2)
5. Net Interest Expense Difference	$ (3,806)	4,987	$ 1,181	
6. Income Tax Rate		40.85%		
7. Impact on Net Income		$ 2,037		

(1) Schedule ANS-23 R-1
(2) Response to RAR-A-15(b)