STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc.	Case 06-G-1332

DIRECT TESTIMONY AND EXHIBIT OF

HELMUTH W. SCHULTZ, III

and

DONNA DeRONNE, CPA

ON BEHALF OF THE

NYS CONSUMER PROTECTION BOARD

Dated: March 16, 2007
Albany, New York

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INTRODUCTION

Q. What are your names, occupations and business address?

A. My name is Helmuth W. Schultz, III, I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory analyst in the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

I am Donna DeRonne, a Certified Public Accountant licensed in the State of Michigan. I am a senior regulatory consultant in the firm Larkin & Associates, PLLC, whose address was identified above.

Q. Please describe the firm Larkin & Associates, PLLC.

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

Q. Have you previously testified before the New York State Public Service Commission?

A. Ms. DeRonne filed testimony in Case 05-E-1222, regarding New York State Electric & Gas Corporation, Case No. 06-G-1185 regarding the Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York, and Case No. 06-G-1186 regarding KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island.

Q. Have you prepared attachments describing your qualifications and experience?

A. Yes. We have included Attachments I and II, which are summaries of our regulatory experience and qualifications.

Q. What is the subject of your testimony?

A. We are testifying concerning the November 2, 2006, rate filing of Consolidated Edison Company of New York, Inc. ("Con Ed" or "Company").

Q. Do you have any exhibits supporting your testimony?

A. Yes. We have three Exhibits. Exhibit__(LA-1), consists of four schedules. Schedule 1 of Exhibit__(L&A-1) presents the impact on revenue requirement resulting from each of the adjustments we are recommending in this testimony. In determining the revenue requirement impact, we utilized the rate of return requested by the Company, and the Company's proposed revenue conversion factor. This does not, in any way, mean that we support the rate of return or revenue conversion factors incorporated in Con Edison's filing. Exibit___(L&A-2) summarizes our proposed Maintenance Program Changes. Exhibit___(L&A-3) consists of two schedules. Schedule 1 consists of a list of the responses to information requests we reference in this testimony and the corresponding page numbers. Schedule 2 consists of the actual responses to the listed information requests.

Q. On whose behalf are you appearing?

A. Larkin & Associates, PLLC was retained by the New York State Consumer Protection Board ("CPB").

Q. Would you please discuss each of the adjustments you are recommending?

A. Yes, we will discuss each of the adjustments we are sponsoring below.

INSURANCE EXPENSE

Q. Are you recommending an adjustment to the Company's requested insurance expense?

A. Yes. The Company's request for $5.8 million is considered excessive, includes costs that do not protect the ratepayers and is not fully supported. The Company was requested to "Provide supporting documentation for the insurance premiums in total" in CPB2, question 12. The response did not provide the supporting documentation requested. For insurance costs other than Directors and Officer Liability Insurance premiums, addressed below, the filing includes an increase of $792,000 for which the Company has provided no supporting documentation.

Q. Please elaborate on your comment that the supporting documentation was not provided.

A. To an auditor, whether it is the Internal Revenue Service, the Company's outside auditor or even the internal audit staff, supporting documentation for the insurance premiums would be the premium notice and/or the policy identifying the cost and the type of insurance that was being billed for. For ratemaking purposes, the same requirements should apply. The burden of proof for costs requested in the filing is the responsibility of the Company. When supporting documentation is asked for, it should be provided. The Company has failed to meet the burden of proof; therefore, the requested increase in premiums should be denied.

Q. Is the adjustment that you are recommending limited to the increase in premiums over the test year amount?

A. No. The cost of insurance in the rate year ended September 30, 2008 includes $1.263 million for Director and Officer Liability Insurance (DLO) premiums. The $1.263 million represents 21.8% of the requested insurance expense of $5.8 million. The DLO insurance cost is excessive and provides no direct benefit to ratepayers. In addition to removing the unsupported increases in insurance premiums contained in the filing, the $1.263 million cost for DLO insurance should be removed.

Q. Why do you contend that the DLO insurance does not provide any direct benefit to ratepayers?

A. DLO insurance is designed to protect shareholders from inappropriate and/or imprudent actions taken by directors and officers. In essence, shareholders are protected from their own decisions by purchasing DLO insurance. If a claim were to be made against the policies for DLO insurance, the recipient of the proceeds paid by the insurance company would be shareholders and not ratepayers. Since ratepayers would not benefit from DLO insurance, they should not fund it.

We are also concerned that the amount of premiums paid for DLO insurance has increased significantly since 2001 and 2002 when numerous corporate accounting scandals were uncovered. Ratepayers have no control over who is appointed to the Board of Directors and they have no control over who becomes an officer of the Company. Consequently, they should not have to be responsible for any potential mistakes that shareholders make when they decide who will be on the Board of Directors. The risk associated with shareholder decisions should be borne by shareholders and so should the cost of insurance that is purchased to protect shareholders from their own decisions. The removal of the DLO insurance premiums from the ratepayers' cost of service is appropriate.

Q. What is the total adjustment that you are recommending for insurance premiums?

A. The insurance expense should be reduced by $2.055 million. The adjustment removes the $1.263 million for DLO insurance and $792,000 for the remaining insurance request that was not supported by documentation despite such information and support being requested.

INJURIES AND DAMAGES

Q. What adjustment are you recommending to the Company's Injuries and Damages expense?

A. The Company's request of $9.108 million should be reduced by $2.685 million to the correct three-year average amount of $6.423 million. The Company's calculation is not as has been represented and it inappropriately includes an increase for escalation.

Q. What do you mean that the Company's calculation is not as it is represented?

A. On page 44 of the Accounting Panel's testimony, it states that "in accordance with prior Commission practice, the rate year level of injuries and damages is equivalent to the annual average of all claim disbursements for the three-year period July 2003 through June 2006." The simple average expense for the Company's gas operations for the three-year period July 2003 through June 2006 is $6.430 million, not the $8.671 million shown in the response to CPB2, Question Number 11. The Company provided five years of historical expense data for injuries and damages for gas operations in their response to Staff2, Question Number 28. For the each of the twelve months ending June 30, 2004 through 2006 the expense was $7.618 million, $4.964 million and $6.707 million, respectively. That three-year period averages to $6.430 million on an annual basis. That simple calculation provides evidence that not only is the Company's representation misleading, but it also shows that the level of expense fluctuates each year. Considering the annual level of fluctuation, the arbitrary application of an escalation factor is inappropriate. There is no evidence to substantiate the application of an escalation rate to Injuries and Damages Expense.

Q. How did the Company come up with the average cost it is requesting?

A. The Company simply applied a 16.2% allocation factor to the total Company three-year average. According to the Company's work papers, the allocation factor of 16.2% has been used to allocate common costs among its electric, gas and steam operations since July 1999. The use of that dated factor for the Injuries and Damages Expense is not appropriate and is not the historical split as is suggested in the response to CPB2, Question Number 11. In fact, by taking the Gas Operations expense for each of the twelve months ending June 30, 2004 through 2006, as shown in the response to Staff2, Question Number 28 and comparing it to the total company expense for Injuries and Damages for the same periods as shown in the response to CPB2, Question Number 11, the annual allocations to Gas Operations were 10.7%, 9.9% and 16.0%, respectively.

The 16.2% factor utilized by the Company in determining the rate year expense significantly overstates the actual Injuries and Damages expense recorded by the Company's gas operations.

Q. How did you determine that the average expense should be $6.423 million instead of the simple average of $6.430 million you identified earlier?

A. In our calculation, we multiplied 12%, which is the three-year average of the Gas Operations allocation as described above, by the three-year average of total Company claims of $53.525 million, that was utilized by the Company as shown in the response to CPB2, Question Number 11. The result is the $6.423 million that should be reflected as the rate year expense.

INTERFERENCE PROJECTS

Q. Have you taken exception to the Company's requested amount for Interference Expense?

A. Yes. The Company's request is overstated by $762,000. The overstatement is due to an inconsistency in the Company's calculation.

Q. What is the inconsistency that you found in the Company's calculation?

A. The Company used averages of three years in some cases and four years in other cases to determine the total interference cost, but then applied the test year percentage to allocate the cost between labor and non-labor. A 97% average Commitment Target was used in determining what the City's expenditure forecast would be. The Company then used an 11% average in determining what amount would be Con Edison's gross O&M Interference forecast and then a 19% average was used to determine the total Gas O&M Interference forecast for the rate year. The inconsistency in the calculation on Company Exhibit__(TMG-1) is the Company's application of the historic test year's labor percentage of 22%, instead of the historical average labor percentage, to determine the rate years Gas Interference expenditure forecast of $16,068,000.

Q. What is required to correct the inconsistency?

A. To be consistent, a historic average of the Gas Interference labor dollars should be applied to the forecasted total Gas O&M Interference Expenditures. The three year average calculated from the response to Staff12, Question Number 222 is 25.7%. By reducing the Company's total calculated rate year Gas Interference Expenditures of $20,600,000 by 25.7% instead of the single year rate of 22%, the Company's rate year Gas Interference Expenditures excluding labor are $15,306,000 instead of

$16,068,000. That results in a reduction of $762,000 to Gas Interference Expenditures shown on Line 27 of Company Exhibit__ (AP-6), Schedule 1, and Page 3 of 5.

UNCOLLECTIBLES

Q. Are you in agreement with the Company's calculation of the uncollectible factor of .54%?

A. No. The calculation is based on the total company and is not specific to the Gas Operations. The Gas Operation's uncollectible rate for each of the twelve months ending June 30, 2004-2006 was .41%, .35% and .49%, respectively. For the twelve months ended June 30, 2003, the Gas Operations' uncollectible rate was .37%. At no time was the rate as high as the .54% level that the Company utilized in projecting its revenue requirement.

Q. What uncollectible factor are you recommending for the rate year?

A. I am recommending an uncollectible factor of .42% based on a three-year average of the Gas Operation's uncollectibles. That would reduce the Company's requested expense of $8,972,528 by $2,033,527, to $6,939,000, using the Company's requested revenue of $1,652,143,000.

To the extent the revenue requirement is reduced below the Company's request, an additional adjustment would be required.

BILL REDESIGN

Q. Are you recommending an adjustment to the costs for the redesign of the customer's bill?

A. Yes. The Company's request includes three types of costs identified as incremental costs associated with the larger bill format being implemented. The added cost identified on line 29 of Exhibit__ (AP-6), Schedule 8 is $93,000. According to the response to Staff13, Question Number 251, the increase consists of the incremental cost for larger envelopes, annual system/software maintenance costs and one time educational material costs for a total of $511,000. Using the Company's 18% allocation factor, the impact on gas operations is $92,000.

We are concerned that the Company's calculation is inconsistent, Con Edison has not provided supporting documentation as requested, and that the request pertains to a one-time cost in the rate year. Also of concern is the Company's assertion in the response to CPB5, Question Number 35, that there are no O&M cost reductions or savings associated with the bill redesign.

Q. Would you please explain your concerns?

A. Yes. The Company's calculation according to the response to Staff13, Question Number 251, states that the gas operations allocation is 18%. The responses to Staff8, Questions 120 and 122, indicate that the allocation for the same costs is 17%. Although the difference is minor, it is indicative of the inconsistencies in the Company's filing. In addition, supporting documentation has not been provided. Staff8, Questions 122 requested that the Company "provide contracts or documentation" for the system/software maintenance costs. The response provided only a summary of dollars, not the contracts or documentation that are necessary to support the Company's request.

Another concern is that rates are being set to reflect the ongoing costs of operations and the inclusion of one-time costs by the Company in its request overstates the ongoing cost of service requirement. One-time costs, if determined to be necessary and beneficial, should be amortized into rates over a period of time. Finally, the assertion that there are no cost reductions or savings is suspect. Generally when one program replaces another, it is reasonable to anticipate some cost reductions in either maintenance or operational costs.

Q. What is your recommendation regarding the requested bill redesign cost?

A. First the one-time cost of $42,480 ($236,000 x 18%) should be amortized over a three-year period, reducing the redesign costs in the rate year by $28,320. Next, the unsupported increase of $8,330 for maintenance associated with the bill inserter and publication support should be disallowed. The result is a total rate year reduction of $36,650 to the Company's request for $93,000 of additional costs for redesigning customer's bills.

PAYROLL

Q. Are there any concerns with the labor dollars included in the Company's rate request?

A. Yes. The Company determined its labor dollars in the rate year based on a number of adjustments to the historical test year without providing an overall summary of the labor included in the rate year. In future rate cases, the Company should be required to include a summary of the labor dollars in the filing that readily identifies the various components of labor dollars being requested in rates as well as a summary of the number of employees and/or full time equivalents (FTE's) being requested.

The labor in the rate year consists of the test year payroll expense adjusted by the average percentage increase to total Company compensation, a normalization increase for law department positions not filled in the historic test year and the cost for adding new employees (referred to as program changes) subsequent to the historic test year. The net increase in payroll expense (i.e. net of productivity savings of 1% per year) from the historic test year to the rate year in payroll expense is 6.7%. We have concerns with the calculation of the rate year payroll, specifically the addition of employees, the amount of overtime and compensatory time, and the payment of variable pay to management employees over and above their base compensation and compensatory compensation (i.e., overtime pay for salary personnel).

Q. Why is it necessary to have the level of detail you have identified?

A. Payroll is a major expense. It accounts for approximately 39% of total operation and maintenance expense excluding fuel costs. Since payroll is such a significant percentage of O&M Expense, the development of the cost should be specific to gas operations and the gas operations employee count should be part of the filing. In the current filing, the payroll detail is related to total company and it is not specific to gas operations.

Q. Did you request more payroll detail than what was included in the filing?

A. Yes. CPB10, Question No. 84(a), requested a summary of payroll dollars for gas operations that identifies the amount of union wages for the year, the amount of management wages for the year, the total payroll dollars for the year and the amount expensed for the period 2002 - 2006, the test year and the rate year. The Company's response was "The Company does not maintain data identifying union and management wages by types of labor, i.e., straight time, premium time, overtime and compensatory time for electric, gas, or steam operations individually." That request did not ask for payroll at the level of detail the Company indicated was not available. In our experience, utilities typically include the requested information in their filing at least for the test year and the rate year. We are concerned that Con Edison was unable to provide this information, even after a specific request.

Q. Is there other payroll detail you requested that was not provided?

A. Yes. A summary of the number of full-time equivalent employees in Con Edison's gas operations was requested for various years. The response to CPB10, Question No. 85, was "The data for gas operations is not available." The same interrogatory also asked for staffing levels for gas operations and the response was the same. We are concerned that the

Company cannot tell us how many staff or fulltime equivalent employees are required to operate its gas operations, but it can ask for more employees and/or fulltime equivalents.

Q. What are your concerns with the projected addition of employees?

A. The Company has reflected an addition for law department positions not filled during the historic test year and it has reflected employee additions for program changes. The Company has indicated that some of the positions requested have been filled but there is also an indication that other positions have not been filled and that additional vacancies have occurred. Based on the response to CPB1, Question Number 10, some of the tax positions requested by the Company have not been filled. Similarly, based on the response to Staff14, Question Number 260, there hasn't been an increase in the number of employees in the law department despite the law department's request for program change additions or the normalization (filling of vacant) positions, the buyer positions requested were not filled in 2006 and the human resource positions requested were not filled in 2006. In addition, according to the response to Staff14, Question Number 266, the new shared service positions were all filled from within the Company, meaning that the employee complement did not increase and the compensation change, if any, is minimal. The Company's projected increase in payroll expense of $1.024 million for additional employees, is considered to be questionable.

Q. Why are you concerned with the projection of overtime and compensatory time?

A. The Company's request reflects an escalation factor that incorporates total Company overtime and total Company compensatory time. According to the response to CPB10, Question No. 84(g), Con Ed cannot provide the amount of overtime charged to gas operations. In our opinion, this is a serious concern because overtime for other operations may be charged to gas operations as part of the allocation process.

Q. What are your concerns with the variable compensation?

A. Variable compensation is a bonus and/or incentive type pay that is over and above the base pay and compensatory pay for management. According to the response to CPB10, Question No. 84(d), "Management employees with at least a satisfactory performance rating are eligible to receive variable pay under the plan." Base pay is for "satisfactory performance." Bonus or incentive pay is added compensation for higher levels of performance that provides a benefit to ratepayers and shareholders.

The arbitrary addition of 6% to management pay for variable compensation is considered to be subjective and is not supported by the record. There is no testimony or supporting work papers to justify adding variable compensation into the payroll expense being charged to ratepayers. There is a concern that shareholders are the primary beneficiary of variable compensation. If the shareholders are convinced that the variable compensation is justified, they should be responsible for its cost.

Q. What amount is included in the rate year for variable compensation?

A. Because the Company's filing does not reflect specific costs for the gas operations payroll expense, the specific amount in the historic test year and the rate year is not readily available. However, based on the response to CPB10, Question No. 84(d), the estimated expense in the rate year is $2,273 million. The response provided "The Company's expense for gas" for each of the years 2003-2006. We averaged data for 2005 and 2006 and escalated it by 5.63%, to obtain our estimate of $2.273 million.

Q. Are you recommending an adjustment to payroll expense?

A. Yes. It is recommended that $512,000, or half of the projected cost of additional employees, be removed because it is not known and measurable at this time whether the projected additions will occur and result in an increase to the employee complement. We are also recommending that the $2.273 million of variable compensation be disallowed because it is not justified by the filing. There is no evidence that the variable compensation is reasonable and/or beneficial to rate payers. The total adjustment to payroll expense in the rate year is $2.785 million.

MAINTENANCE PROGRAM CHANGES

Q. Have you reviewed the Company's request for maintenance costs under the caption program changes?

A. Yes. The Company's request for $9.969 million consists of $9.2 million of estimated costs for contract labor and $.8 million of estimated costs for materials and supplies. According to the response to Staff9, Question 149, five of the ten projects are new O&M programs and therefore no budget or historical actual expense data exists. The Company in its response to NYECC1, Question Number 11, indicated that all the programs except the IR maintenance service contract are either safety-related, maintenance of transmissions mains or preventive maintenance/mitigation.

Q. Please provide an overview of your concerns regarding these proposed maintenance program changes.

A. Cost-effective maintenance of Con Edison's gas system will benefit ratepayers by helping ensure safe and reliable service and by helping hold down the costs of utility service in the long run. It is possible, however, that projects alleged to be required for safe and reliable service, may not be in the public interest. The Commission should review proposed maintenance projects, just as it evaluates other proposed expenditures, to be sure that they are cost justified. It should not assume that all projects deemed by the Company to be safety-related or for maintenance, are in fact appropriate.

We are concerned that the Company has not demonstrated that several of its proposed maintenance program changes are in the public interest. Moreover, Con Edison's claims that the programs are safety-related or for required maintenance, raises questions about why they were not implemented before this time.

Q. Are there concerns about the cost estimates included in the filing?

A. Yes. The Company's testimony that describes this significant increase in O&M expense is very brief and provides very little cost detail. The work papers for the cost estimates for the maintenance programs identify unit costs and calculations but include no specific supporting documentation. Projects 3,4,5,6 and 8 all have contingency dollars built into the cost estimates. Next, the Company has indicated that a number of the projects will extend the life of the assets involved or the cost of the project is for the replacement of assets, and yet it has elected to expense the cost because the work is consider a minor item. As stated above, historical costs to verify the reasonableness of the estimates are generally not available and absent real quotes or bids, the estimates are just guesses. In fact the Company has stated in the response to Staff9, Question Number 146, that the Hurricane Preparedness cost, is "based on best guess estimate since no device is currently available".

Finally there are a number of cost estimates within the $9.969 million that are one-time expenses estimated to occur only in the rate year. If rates are set to include these costs, ratepayers could continue to pay them in future years even though the cost is no longer being incurred. There are concerns with each of the ten requested projects.

Project 1

Q. What concerns are there with the cost estimate for Project 1?

A. Project 1 involves an increase in the number of annual inspections of local isolation valves as a result of a plan to change from a ten-year inspection cycle to a five-year cycle. The Company, according to the responses to Staff9, Question Numbers 133 and 134, can identify the total number of local isolation valves that were inspected and the number of local isolation valve faults found, but it cannot provide a specific cost for the inspection of the isolation valves and/or for the cost to repair and/or replace the isolation valves where defaults were found. The Company's reason for not providing the cost information is that the Company does not track the costs.

Our second concern is that the estimated cost for the program change is based on an average inspection cost for all distribution main valve inspections and the average cost of repairs for main valve fault repair costs in a single operating area. It is not appropriate to base the cost of the program on costs associated with valves that are not part of the isolation valve program. It is also troubling that the Company would request to significantly accelerate its maintenance program without investigating the specific cost of the program and/or doing a cost benefit analysis. When asked in CPB11, Question No. 86(c) to provide contractor invoices for local isolation valves, the Company provided invoices for "main valve fault repairs not exclusive to local valves."

Another concern is that this project is being classified by the Company as a safety program change but it has failed to justify it as a safety issue. The Company attempts to justify the program by stating in its pre-filed testimony that a shorter interval between inspections will improve reliability and efficiency and that it will reduce the risk that a valve will not be accessible during an emergency, without providing support for that position. When questioned about the accessibility of the local isolation valves, the Company stated in response to NYECC1, Question Number 12, that the Company doesn't track information that would identify how often local isolation valves were not accessible. When asked to explain how the risk that a local isolation valve would not be accessible during an emergency would be reduced, the Company stated in response to that question that "A shorter inspection interval increases the Company's ability to address a valve that has become inaccessible or inoperable." The Company's response did not provide an answer to the question or justify its assertion in its pre-filed testimony. The Company's testimony and its responses to interrogatories have failed to justify the increase in inspections from a ten-year cycle to a five-year cycle, and the

Company has not provided sufficient detail and/or analysis to quantify the cost of the proposed accelerated maintenance program.

Q. Are you recommending an adjustment to the isolation valve project cost request?

A. Yes. We recommend that the entire $862,000 be disallowed. The Company has failed to provide evidence that shows that reliability and efficiency will improve from an accelerated maintenance program. It also has not properly quantified the cost of the program change and has not provided a cost benefit analysis that would justify the increased cost of the program change.

Project 2

Q. What concerns are there with the Atmospheric Corrosion Control project?

A. Project 2 consists of a program to clean, coat and repair 7,070 feet of pipe and 314 supports over a three-year period at a net cost to Con Edison customers of $5.1 million. This project is discussed in the transmission maintenance section of the Company's testimony on program changes. The concerns that have been identified are the lack of similar maintenance in recent years and the lack of support for the cost projection included in the filing.

Q. What is the concern with the lack of similar maintenance in recent years?

A. The Company was requested in Staff9, Question Number 135, to provide historical cost information for this program change from 2003 to the present. The response provided the 2004 cost of $504,000 for 450 feet of pipe and ten pipe supports. No information for 2003, 2005 or 2006 was provided. Based on the response, the Company only performed this type of maintenance on 450 feet of pipe in the last four years (approximately 112 feet per year) and now is proposing to perform maintenance on 7,070 feet over the next three years or approximately 2,350 feet per year.

The proposed increase in maintenance is significant. Either the Company has been neglecting this maintenance in recent years or it has not been forthcoming in their response to interrogatories. Based on the level of historic maintenance the Company has indicated that it has performed in recent years, there is no assurance that the proposed maintenance will in fact occur at the level proposed.

Q. What support did the Company provide for the cost included in the filing?

A. The Company has not provided any support for the cost included in the filing. It was requested in Staff9, Question Number 135, to provide work papers explaining how the cost to repair piping and supports were derived. The response simply provided the same detail that was included in Company witness Mr. Frank Ciminello's work papers, which was the length of pipe, the number of supports, the total cost, the percentage that Con Edison was responsible for and the net cost. There are no contractor estimates, quotes or bids, there was no explanation of how the total cost was derived (as was requested) and as discussed earlier, there was almost no historical information that could even be used as a proxy for determining the reasonableness of the Company's cost estimate.

Q. Was there any further attempt to obtain supporting information?

A. Yes. Supporting documentation was requested in CPB11, Question No. 87 and the response referred to Staff 135. No supporting documents were provided for either responses. The response to CPB 87 also stated there currently are no bids yet, but there will be prior to the proposed project start date in 2008.

Q. Are you recommending a cost adjustment for Project 2?

A. Yes. Absent evidence to the contrary, we assume that maintenance will in fact increase, but not at the level proposed. We recommend that the Company be allowed recovery of the cost to perform on an annual basis twice the level of maintenance that was performed in 2004 or $1,008,000 for maintenance. This recommendation is on the condition that the Company is required to complete at least that level of maintenance and that any expenditure less than that should be set aside as a regulatory liability for future work. Allowing $1,008,000 would reduce the Company's request for $1,700,000 by $692,000.

Project 3

Q. What is project number 3?

A. The third project is Transmission Main Maintenance. The Company has requested $2.26 million for what has been identified as a new maintenance program. The project calls for the installation of welded sleeves on the Bronx portion of Con Edison's gas transmission line because there is a possibility that leaks will occur from the transmission of the drier Canadian gas that will be received in the system. The installation of the welded sleeves is a three-year program estimated to cost $6.78 million.

Q. Are there concerns with the proposed program change for transmission maintenance?

A. Yes. The Company has not provided documentation to support the cost estimate, the estimates include a contingency, the project is to address a potential concern (i.e. Company testimony states drier gas “can cause” gaskets to shrink and “could result” in leaks) and we would consider the cost of the project, if completed, to be a cost to be capitalized and not expensed.

Q. What has the Company provided for support for the projected cost?

A. In the response to Staff9, Question Number 136, the Company included a summary of the work to be done including quantities and unit costs. Added to the project’s sum total is a 15% contingency. While the detail in this cost estimate is better than for most of the other maintenance projects, there still is no documentation supporting the quantities or the unit costs. The Company’s response states that the estimate is based on prices from area contracts. If this is the case, the supporting documentation should be readily available, and if it is based on actual contract work, there should be no need for a 15% contingency. It is also interesting to note that when asked about historical costs, the Company was again unable to provide cost information because it did not separately track these costs even though work of this nature has been performed from 2003 to present.

Q. Was another attempt made to secure supporting information?

A. Yes. CPB11, Question No. 88(b), asked the Company to "Provide any supporting documentation relied on to develop the estimates." The response reiterated the response to Staff 136, that "Estimates were based on actual bid units and hourly prices as reflected in work papers submitted with the response to Staff 136." Numbers on the work papers do not constitute supporting documentation.

Q. Why is there a concern about the contingency?

A. If a project is properly planned and priced based on quotes and/or bids, then a reasonable price can be determined. Bids and/or quotes generally include a built-in contingency. A contingency provides a cushion for the Company that if not utilized, results in a windfall to shareholders. In this specific project, the Company is seeking approximately $850,000 over three years, or $283,333 a year. Ratepayers are not protected in any way from the Company's failure to properly quantify its project costs and have no recourse if the project is completed without the contingency.

Q. What if there is no contingency and the project cost exceeds the estimate?

A. The Company is provided an opportunity to earn a return that fairly compensates it for this risk. In addition, if the costs exceed the estimate and the excess cost can be justified, the Company can file a new rate request that reflects the increase in costs. Even without a contingency there is some protection for the Company and its shareholders but with a contingency there is no protection for ratepayers. The Company was asked if there was any assurances that the cost to ratepayers was reasonable and the project will be completed when indicated. The response to CPB11, Question No. 88(e) provided no assurance and indicated costs will vary.

Q. Could you explain why you referred to the possibility of a leak as a potential concern?

A. The Company's testimony states that the gaskets can shrink and leaks could occur. According to Staff13, Question Number 229, the Company had 2 leaks of this nature in 2006 but none for the 2003-2005 time periods. There has been no evidence presented that would validate the

Company's claim that the gaskets would shrink and the leaks would occur. When asked to provide a study or studies in Staff15, Question Number 279, the Company response simply made reference to other utilities' experience and the Company's participation in industry discussions but failed to provide any studies and/or supporting documentation.

Q. Why should the cost of the Transmission Main Maintenance program be capitalized?

A. The Company stated in response to Staff13, Question Number 231, that it expects that sealing the coupling will increase the life expectancy of the gas main. The Handbook of Accounting and Auditing published by Warren, Gorham & Lamont specifically states "Regardless of how they are described, expenditures that extend the useful life of capital assets or increase their productivity should be capitalized as an addition to the individual or composite asset account".

Q. Does the Company have support for expensing the project cost?

A. No. The Company was asked to provide supporting documentation for including the cost in O&M. The response to CPB 88(a) consists of a page from the Con Edison Property Accounting Manual dated July 1980. The tasks under maintenance are repairing leaking joints, broken mains, leaks, etc. This Company accounting guidance is for a leak, not for a project that is preventative and of a significant nature. Further, the Company's accounting manual is not authoritative. In fact, when questioned about capitalization under GAAP in CPB 88(f), the Company simply stated that "The Company believes" this project is an O&M function.

Q. Are you recommending that the cost be allowed as a capital cost?

A. It is our recommendation that, subject to the Company's provision of supporting documentation for the cost estimate, the Company be allowed to capitalize the estimated cost excluding the contingency. That recommendation would reduce operating and maintenance expense $2,260,000 and increase plant approximately $993,300 (50% of $1,986,000), the average of the annual amount expended.

Project 4

Q. What type of project is the Pressure Control Program?

A. The Pressure Control Program consists of three different projects: the upgrade of remote-operated valves (ROV), the inspection and improvements to gas regulator manholes and the elimination of select regulator station by-pass valves.

Q. What are your concerns with the Company's requested increase in cost of $666,000?

A. The Company has indicated in the response to Staff9, Question Number 149, that the program costs requested are incremental costs, yet it could not provide historical costs for the ROV program and the regulator manhole program because it does not track this information. As for the by-pass valve program there have not been any valves eliminated in the years 2003-2006 so there were no historical costs incurred for this supposed incremental expense. Finally the limited detail included in the work papers and responses does not provide sufficient information to verify the determination of the cost or the reasonableness of the cost estimate.

Q. Should an adjustment be made to the Company's cost request?

A. Yes. First the rework of the ROV is intended to correct 30 units over a five-year period or 6 units a year. The project is supposed to increase reliability and presumably reduce maintenance. In the year 2006, which is part of the test year, there were ten ROV repairs made. The ten repairs identified in the response to Staff9, Question Number 138, are significantly more than the failure rate of one per year identified in Mr. Frank Ciminello's work papers. With the significant level of repairs in 2006, the test year includes expenses that are substantially greater than the normal level of expense. However, the Company's calculation of rate year expense does not adjust for either the increased level of expense in the test year or the fact that the program would lead to lower repair costs because there are fewer units subject to failure. In addition, the Company has not adequately explained or shown how the cost estimate was determined and there is no supporting documentation for the estimate.

Q. Was there an additional attempt to get more information?

A. Yes. An explanation and supporting documentation was requested. The response to CPB11, Question No. 89(a) provided a breakdown of the cost, but still no detailed explanation or supporting documentation was provided.

Q. What adjustment to the ROV costs are you recommending?

A. The first adjustment removes the entire unsupported cost increase requested for the program of $156,000. The second adjustment removes an estimated cost of $120,000 to account for the abnormal number of repairs in the test year. The $120,000 estimate is based on the assumption that half of the ten repairs in 2006 were done in the test year. Since the Company stated that the normal failure rate is one a year, we are adjusting for the four extra repairs in the test year. The cost estimate used for the repairs is $30,000 per repair.

Q. What is your basis for using $30,000 a repair?

A. The Company is proposing to rework the ROVs at a cost of $26,000 each. We assume this rework is cost beneficial, therefore the repair costs are assumed to exceed the rework costs. Since the repair cost information requested was not provided by the Company, it is our belief that this is the best estimate of the cost to repair each unit failure.

Q. Is there an adjustment required for the improvements to the regulator manholes?

A. Yes. The Company's calculation of the estimated cost for this portion of Project 4 was provided in the response to Staff9, Question Number 139. The calculation shows the various components of the proposed ten-year cost calculation but there is no explanation or supporting detail for the unit costs. The ten-year cost also reflects a $235,360 contingency. The original estimate essentially includes unsupported numbers on a piece of paper. It is also interesting that this incremental cost does not reflect any cost reductions and/or savings in the calculation. That means the inspection costs and any repair costs included in the test year will, based on the Company's failure to reflect any offset, continue despite the improvements being proposed. We recommend a reduction of $142,000 to the Company's request for $260,000 for the manhole improvement campaign.

Q. How did you determine your adjustment?

A. The Company's request as stated earlier included a contingency of $235,360 or $23,536 a year. First, we removed the contingency from the annual requested amount of $260,000 leaving a balance of $236,464. Then, assuming that this incremental program would produce some cost savings, we estimated the savings to be one-fourth of the remaining cost estimate, or $59,116, leaving a balance of approximately $177,348.

Q. If the cost were not fully supported why would you leave some of the costs in the rate year?

A. The Company provided some level of detail for this project, therefore it seems reasonable that there will be some net cost incurred. The Company eventually provided some support for some of the numbers (not all) in the response to CPB11, Question No. 89(b). Based on that response it appears some material costs may be high so the cost estimates already include a contingency.

Q. Is there an adjustment to be made for the request for $250,000 for the by-pass valve elimination included in the Project 4 estimate?

A. Yes. The Company's request to eliminate 10 valves per year at a cost of $25,000 per valve is not supported by the filing. The Company has no historic cost to substantiate the cost estimate and has not included any detail in the filing to explain and/or show how the cost-per-valve estimate was determined. Again the Company has simply put a number in the filing without any supportive detail. An added request for supporting documentation did not result in any new information. The Company's failure to justify the requested amount is reason enough to disallow the entire $250,000.

Q. What if supporting documentation had been provided?

A. If the Company had provided supporting detail and/or documentation for the cost estimate, we would still recommend that the cost be removed from O&M expense, but we would then recommend that it be allowed in capital additions. Testimony by the Company suggests that the elimination of the valves would increase the life expectancy of the system. As stated earlier, if the expenditure of funds extends the life of an individual or composite asset the cost should be capitalized.

<u>Project 5</u>

Q. Could you explain the Company's request for the Tunnel Program?

A. The Tunnel Program consists of three different programs. The first is the inspection, coating removal, repair and recoating of the mains in tunnels over a period of years at an estimated annual cost of $135,000. The second program is the replacement of twenty Catalytic gas sensors with Optoacoustic sensors in the rate year only, at a cost of $205,000. The third program replaces roller assemblies and repairs deteriorated sections of concrete piers in the rate year at an estimated cost of $405,000. This pier and assembly work is a rate year only program. The response to Staff9, Question Number 141, provides a very brief explanation on how the costs were developed and includes an attachment showing the calculation of the estimates. The Company asserts that the costs of this project are incremental costs.

Q. Is there justification and/or supporting documentation for the first program cost estimate?

A. There is justification for work of this nature on an ongoing basis. However, the Company has stated in its response to Staff9, Question Number 141, that "It has been several years since any major removal and re-taping of any New York Facilities gas mains in any of the tunnels has been performed and no actual cost reports are available".

Essentially the Company has not been performing the maintenance that it is now proposing to do on an annual basis. The estimate that the Company develops is based on discussions and not on written contractor estimates and/or quotes. And again, the Company has plugged an extra amount into the cost for a contingency, in this case approximately $12,000 on an annual basis. There is justification for the program but there is no supporting documentation for the cost estimate. Support was provided for some material costs, but there was not sufficient detail to verify the estimate.

Q. Are you recommending an adjustment be made to the cost estimate?

A. Yes. The estimated annual cost should be reduced $12,000 for the contingency. We reluctantly recommend that the remaining costs be allowed on the condition that the Company provides supporting documentation for the cost estimate in the form of written bids and/or quotes and it is required to track the cost and report the progress of the project to the Commission.

Q. Is the cost estimate for the sensors replacement program sufficiently explained and supported by the Company?

A. No. The Company has shown how the cost was calculated, but it has not included sufficient cost documentation for all the amounts, time and/or quantities in the calculation. The response to CPB11, Question No. 90(c), provided support for the unit cost of the sensors. However, the total cost is inflated first by a $17,200 contingency and then by $15,800 of rounding. That is a 19% cushion over the calculated estimate.

The program provides for the replacement of existing Catalytic sensors with new Optoacoustic sensors. The work papers of Mr. Frank Ciminello indicate that the new Optoacoustic sensors do not degrade over their life span like the Catalytic sensors and they will provide accurate and reliable detection. That may provide the justification that is needed to allow the cost in the rate year but it is indicative of capital costs. Since all the sensors are supposed to be replaced in the tunnels then the cost of the sensors being replaced should be removed from the filing but they were not. Finally the program is a replacement that is supposed to provide a benefit in the future because of the reliability. The matching principle for accounting would suggest that the cost of the program be capitalized and amortized over the period benefited.

Q. What adjustment are you recommending to O&M expense for this program cost?

A. O&M expense should be reduced by the $205,000 requested and plant should be increased by $86,000 (($205,000 – cushion of $33,000) x 50%) which is the average addition for the rate year excluding the extra cushion the Company included in the estimate.

Q. Should the cost of the concrete repairs and roller assembly replacement be allowed?

A. Not entirely. The same issues exist with this program. The estimate is not supported by historical costs, written quotes and/or bids and the estimate includes a $36,871 contingency. According to the response to Staff9, Question Number 143, there were no replacements or costs incurred for this program for the years 2003-2006 and there is no record of any past replacement. This program is a new program and is not an incremental cost to an existing program as the Company has indicated. Based on the limited detail provided by Con Edison, the repairs appear to be necessary; however these are capital costs, not O&M expenses. According to Mr. Frank Ciminello's workpapers, the items being replaced have reached the end of their useful life. The costs incurred to replace the roller assemblies and the concrete piers will provide a benefit over some future period and the cost should be expensed over that future period of time.

Q. What is your recommended adjustment for the third program in Project 5?

A. The entire $405,000 requested should be removed from O&M expense and $184,500 should be added to plant. The $184,500 is 50% of the cost estimate of $405,000 less the approximate $36,000 contingency.

Project 6

Q. Would you identify the types of programs and the cost estimates included in Project 6?

A. Project 6, the LNG Programs, includes four programs at a combined cost of $714,000. The programs address replacement of the pipe supports, recoating of the concrete berm walkway at the LNG plant, asbestos removal and lead abatement. Some of the estimates indicate that the costs are based on contracts or quotes. The estimate also includes a contingency of $64,500. Supporting documentation was provided for only two of these programs, the recoating of the concrete berm and the lead abatement work, although it was specifically requested for all project costs.

Q. Are you recommending an adjustment to the cost estimate for Project 6?

A. Yes. The contingency of $64,500 should be removed from the Company's request. The remaining cost of $649,500 should be allowed on the condition that the Company produces sufficient documentation to support the unit costs reflected in the respective program estimates. This project is concurrent with the LNG plant upgrade and based on the limited explanations provided, appears to be necessary. There may be some question about whether the costs should be capitalized along with the plant upgrade. However, since the most of the costs are expected to occur for more than one year, the expense may be reasonable if the cost and accounting treatment is properly supported. The recommendation is qualified because accounting guidelines suggest the cost of asbestos treatment be capitalized as a betterment to the property being improved.

Project 7

Q. What is the Southern Manhattan CI Joint Sealing Project?

A. The Company is requesting $760,000 for preventive joint sealing on an accelerated basis in lower Manhattan. The work is to be done in conjunction with, or in anticipation of, City work. The estimate assumes that over the next three years, the Company will seal approximately 400 joints per year in lower Manhattan. Over the last four years (2003-2006), the Company has sealed on average 2,452 joints a year at an average cost of $1,782 per joint. That would suggest that the cost estimate by the Company may be reasonable for the proposed project.

Q. Does that mean that you do not have any concerns with this project estimate?

A. No. There are concerns. First, the project involves the sealing of joints that are not leaking. Second, the project is designed to be preventative maintenance. The fact that the Company would be doing preventative maintenance suggests that there should be a reduction in the number of leaks that will require sealing. As with the other projects or new costs that the Company has included in this filing, there has not been any cost savings reflected to account for a reduction in repairs or costs incurred in the historic test year. Third, a follow-up request for supporting documentation for the cost estimates did not produce any new information. However despite our concerns, we do not recommend an adjustment at this time.

Project 8

Q. What is the Hurricane Preparedness program?

A. The Company is requesting $935,000 in the rate year for a proposed hurricane impact study and the cost for the first year of a ten-year program for installing water-tight check valves on elevated pressure gas service vent lines. After the rate year, the only cost will be the cost of the check valves. Even though the Company plans to complete the program over ten years, it is requesting funding for the impact study in the rate year.

Q. What concerns are there with the Company's request?

A. Mr. Frank Ciminello's work papers indicate that the Company will secure a consultant to perform the impact study at an estimated cost of $700,000 and the Company's testimony states that the Company will "plan" to commission a study. The Company has estimated the cost of the check valve project to be $2,130,000 over the ten years plus a contingency of $213,000. According to the response to Staff9, Question Number 146, the cost estimate per check valve is "based on a best guess estimate" because the Company has "no prior experience with the installation of check-type valves installed on vent lines to house regulators." The valve proposed is a proto-type check valve. The valve is supposed to be designed to provide protection from a storm surge from a category 3 hurricane even though the areas to be protected "have not experienced a category 3 hurricane (wind and storm) occurrence in the recent past." The response to CPB11, Question No. 93, indicated that the vendor of the proto-type provided an estimate, but no documentation was included with the response to support the cost.

Q. What recommendation are you making for the cost estimate in Project 8?

A. I am recommending that the $700,000 estimated cost of the study be disallowed at this time. There is no evidence that the study will in fact take place. If the Company does plan to secure a consultant to perform an impact study, it should obtain authority from the Commission to defer the costs of the study. This treatment allows for the review of the study and if found to be necessary, the cost could be amortized over a period of time. Theoretically the study will provide a benefit over future periods and the cost of that benefit should then be amortized over the period of the benefit.

There is also concern about asking ratepayers to pay for a proto-type valve when the Company has no prior experience with check-type valves on vent lines to house regulators. The project seems to have merit. However, to undertake a major project without first testing the equipment and verifying the cost, is a gamble and could be considered to be imprudent. Finally, even if the cost could be determined and the project was found to be prudent, the costs should be capitalized instead of expensed. The $235,000 a year for the valves should be disallowed because the cost and the project are not known and measurable.

Project 9

Q. Do you agree with the Company's request to expense certain costs associated with the replacement of cast iron mains?

A. No. The replacement of the mains is akin to the installation of a self-constructed asset. The Handbook of Accounting and Auditing published by Warren, Gorham & Lamont includes a discussion on self-construction, which states "All the costs of putting the asset into the condition and location for use are capitalized." Typically when an asset is put into service, all costs are capitalized. We are not aware of any authoritative exception to this policy. In response to a request that the Company provide its guidelines and authoritative accounting guidelines regarding this issue, it provided only the Company's accounting policy. An authoritative guideline that would support the Company's accounting guidelines was not provided. Without authoritative support the Company's position is not supported.

The Company's request for O&M treatment of the costs associated with the capital project should be denied. O&M expense should be reduced by $733,000. If the PSC determines that this capital program is justified, the costs should be capitalized.

Project 10

Q. Are you recommending an adjustment to the projected costs for IR Annual Service Maintenance Contracts?

A. Yes. The Company's response to CPB11, Question No. 95 states "These cost estimates for the annual service contracts are based on the existing contracts with vendors that are being continued." There is some concern that the Company has reflected only additional costs or duplicated the cost for service maintenance for software. It is uncommon for there only to be added costs since other programs typically become obsolete and no longer used. As a result, the need for maintenance contracts on those programs should disappear along with their cost. Because this appears to be a duplication of costs and even if not a duplication of costs because support was not provided as requested, the entire $594,000 should be disallowed.

Summary

Q. Have you prepared a summary of your recommended adjustments to the maintenance program changes?

A. Yes. Attached, as Exhibit__(L&A-2), is a listing of each of the respective projects, including the sub parts to the projects. On this schedule, we have listed the Company's requested amount and the respective recommended adjustments that reduce projected O&M expense by $7.372 million.

RESEARCH & DEVELOPMENT

Q. Have you reviewed the Company's projection of Research & Development expense?

A. Yes. The Company has requested an increase of $2.15 million from $3.7 million in the test year to $5.85 million in the rate year. The 58% increase includes $1.869 million for various projects and $281,000 in escalation. In reviewing Company Exhibit__EE-1, it was noted that the number of projects in the rate year is double the number of projects in the historic test year. The rate year increase for internal R&D was $1.5 million or 66% above the $2.3 million expended in the test year. This expansion in the number of projects is extraordinary. And the requested spending appears to be a “wish list” when compared to historic spending.

Q. What is the historic spending for Research & Development?

A. The five-year average for the twelve-month periods ended June 30, 2002-2006 is $2.7 million. Extracting the 2003 cost, because it is abnormally low due to credits from capitalizing prior year costs, the four-year average is $3.13 million. R&D spending fluctuated from one year to the next and does not reflect a steady increase. The highest level of the combined Internal R&D and Millennium R&D spending occurred in 2006 with $3.7 million being expensed. Internal R&D expense was higher in 2002 than in 2003, 2004 or 2005.

Q. Are there concerns about the Company’s list of proposed R&D projects?

A. Yes. Staff requested information on thirteen of the internal projects, all in excess of $50,000. In response to Staff3, Question Number 54, the Company stated that “Cost benefit analysis are performed if the projects are initially expected to cost in excess of $50,000, shortly before expenditures are about to commence” and that of the thirteen listed only two met this qualification. In reviewing the two cost benefit analysis for the rate year it was noted that the analysis were done in 2003 and 2005. It appears that the other projects are not "about to commence" and that activity on the project does not necessarily start right after the cost benefit analysis is complete, as evidenced by the date of the analysis supplied. There is not sufficient evidence to justify a 58% increase in R&D spending.

Adding to this concern, the Company applied an escalation factor to the proposed rate year spending. As indicated earlier, spending fluctuated from year to year so adding the escalation to the rate year request is considered excessive.

Q. What amount of expense are you recommending for R&D?

A. We recommend that the test year expense level be escalated with no additional increases. The rate year increase of $1.869 million and the escalation added to the Company's rate year amount should be disallowed. As previously indicated, earlier spending fluctuated from year to year. If the rate year was estimated based on an average, the R&D adjustment would be a reduction to the test year level. Allowing an escalated test year amount may be reasonable even though it ignores the historical year to year fluctuations.

GAS SURVEYS

Q. Is there an adjustment required to the Gas Survey expense on Line 14 of Company Exhibit__AP-6, Schedule 8?

A. Yes. In response to Staff13, Question Number 252, the Company acknowledged that the estimate for Gas Surveys should be reduced from $150,000 to $75,000 based on the selection of a consultant to perform the surveys.

PENSION & OPEB EXPENSE

Q. What amount has the Company included in the filing for pension and OPEB expense for the rate year ending September 30, 2008?

A. The Company's filing includes projected rate year pension and OPEB expense of $13,953,000. It also includes $11,463,000 for a proposed three-year amortization of the projected pension and OPEB deferral balance as of the start of the rate year. Combined, these two items result in $25.4 million of expense in the projected rate year. This is identified in the Company's application as one of the major increases in costs necessitating the requested rate increase.

Q. What was the amount of pension and OPEB expense recorded by the Company for its gas operations for the historic test year ended June 2006?

A. The actuarially determined pension and OPEB expense applicable to the gas operations for the historic test year ended June 30, 2006 was $6,352,000. However, under the Joint Proposal adopted by the Commission in Case 03-G-1671, the pension and OPEB expense included in rates during that period was actually an income amount of $6,020,000. In other words, rates during the historic test year factored in a negative pension expense, or pension income, of $6,020,000. As a result, the Company recorded a deferral on its books of $12,372,000, which is the difference between the actuarially determined pension and OPEB expense of $6,352,000 and the pension and OPEB income level of $6,020,000 factored into rates.

Q. Should any adjustments be made to the pension and OPEB expense included in the Company's filing?

A. Yes, we are recommending two separate adjustments to the pension and OPEB expense contained in the filing. The first adjustment is a recommended $2,066,100 reduction to the $13,953,000 pension and OPEB expense included in the adjusted rate year. The second adjustment is a recommended $8,379,900 reduction to the proposed $11,463,000 of deferred pension and OPEB amortization expense.

Q. Why are you recommending the projected $13,953,000 of pension and OPEB expense be reduced?

A. Since the time the Company prepared its filing, it has received updated pension and OPEB expense estimates from the firm that prepares its actuarial reports. The letters from the actuarial firm performing the calculations, Buck Consultants, were dated January 15, 2007 and January 19, 2007 for the pension and OPEB plans, respectively. The updates, which were provided in response to Staff14, Question 273, incorporate more recent information and reflect the impacts of the actual December 31, 2006 pension and OPEB plan assets. There were also revisions made to some of the actuarial assumptions based on more recent information and projections. For example, the projected discount rate used in the actuarial calculations for both the pension plan and the OPEB plan has increased from 5.70% to 6.0% and the health care cost trend rates have been increased from 8.0% in 2007 to 9.0% in 2007. We recommend that the projected pension expense for the rate year be revised to reflect the updated actuarial calculations. According to Exhibit__(AP-6), Schedule 10, the Company intends to update the pension & OPEB expense contained within its filing. We anticipate that the planned update will incorporate the impact of the more recent actuarial calculations.

Q. Did the updated information provided in response to Staff14, Question 273, specifically identify the impact of the updates on Con Edison's gas operations and on the expense included in the rate year in the filing?

A. No, it did not. The information provided by the Company consisted of the updated calculations from the actuarial firm and was provided on a total Con Edison basis.

Q. Since the information was not provided on a gas operations basis, how did you estimate the impact on the pension and OPEB expense contained in the filing?

A. Our calculation of the estimated impact on the amount of pension and OPEB expense for the gas operations is presented on Exhibit__(L&A-1), Schedule 2. Based on a comparison of the updated information provided in the response to the total Con Edison amount that was contained in the workpapers presented by the Company in this case, the total Con Edison pension and OPEB cost for the rate year ended September 30, 2008 has declined by 14.81%. We applied the 14.81% reduction factor to the total pension & OPEB expense included in the rate year in the filing of $13,953,000, resulting in a reduction of $2,066,100 ($13,953,000 x 14.81%). This results in a revised projected rate year pension and OPEB expense of $11,886,900. Since the pension and OPEB costs are allocated from the total Con Edison level to the gas operations, the overall percentage reduction to the total Con Edison costs should also be applicable to the gas operations.

Q. Please provide a summary of the Company's request with regards to the pension and OPEB plan deferral.

A. The Company is currently on the Commission's Pension Policy Statement. As a result, it has been deferring on its books the difference between the amount of pension and OPEB expense included in rates as a result of the Commission's adoption of the Joint Proposal in Case 03-G-1671 and the amount of pension and OPEB expense it actually incurs. The projected deferral balance included in the Company's filing consisted of the actual amount deferred as of June 30, 2006 of $15,477,296, plus an additional $18,911,663 it projected to defer during the period July 1, 2006 through September 30, 2007. The combination of the actual and the projected amounts resulted in a projected deferral balance at the start of the rate year of $34,388,958. The Company is proposing to recover this projected deferred balance from ratepayers over a three-year period, including $11,462,986 in rate year amortization expense for recovery of the estimated deferral.

Q. Are you recommending any revisions to the projected September 30, 2007 deferral balance?

A. Yes. We are recommending a $3,558,100 reduction to the projected deferral, resulting in a revised deferral balance to be recovered from ratepayers of $30,830,900. This reduction incorporates two revisions to the Company's proposed amounts. As shown on Exhibit No.__(L&A-1), Schedule 3, the first step was to reflect the actual amount deferred through December 31, 2006. As previously indicated, the Company's filing incorporated the actual balance through June 30, 2006 and included estimated deferrals for the remainder of 2006 and for 2007 through the start of the rate year. Our calculation reflects an additional six months of actual information.

On the schedule, we also reduce the amount to be deferred for the period January 1, 2007 through September 30, 2007. The Company had projected that $11,998,200 would be deferred on its books during the nine-month period. The amount was calculated based upon the pension and OPEB expense calculations incorporated in the Company's filing. As previously indicated, the Company's actuarial firm has reduced the projected pension and OPEB costs based on updated information and more recent actuarial assumptions. The projected total Con Edison 2007 pension and OPEB costs have declined from $182,600,000 to $164,900,000, a reduction of 9.7%. We applied the 9.7% reduction factor to the amount projected to be deferred by Con Edison for the gas operations for the period January 1, 2007 through September 30, 2007.

Q. Do you agree with the Company's proposal to recover the pension and OPEB deferral from ratepayers over a period of three years?

A. No, we are recommending a longer amortization period. Over 50% of the pension and OPEB costs included in the filing are for the amortization of amounts that have been deferred. As previously indicated, the Company has identified the pension and OPEB costs as one of the major factors in this case causing the need for its requested rate increase. Considering the large proposed rate increase, coupled with other cost increases ratepayers are bearing associated with high gas commodity costs, we recommend that the Company recover the deferred balance over a longer period. This would help to mitigate the impact of the rate increase while still making the Company whole in this area. Specifically, we are recommending a ten year amortization of the deferred balance instead of the three years proposed by the Company.

As shown on Exhibit No.__(L&A-1), Schedule 3, the reduction to the projected deferral balance coupled with a lengthening of the amortization period to ten years would result in an $8,379,900 reduction to the amortization expense.

REVISED CAPITAL EXPENDITURE BUDGET – 2007

Q. Since the time the Company filed its case, have any significant revisions been made to the capital expenditure budgets as compared to those factored into the plant additions in the Company's filing?

A. Yes. In determining the rate year level of plant-in-service, the Company began with the actual June 30, 2006 plant balances. It then factored in budgeted capital additions for subsequent periods along with estimated retirements in deriving the plant-in-service balances factored into the rate year ending September 30, 2008. Under the Company's capital expenditures budgeting process, the preliminary budget is presented to the Company's Finance Committee and Board of Trustees in October of each year and a final budget is presented to the Board of Trustees in November. Thus, at the time of the Company's filing, the 2007 capital expenditures budget would not have been finalized or approved by the Board of Trustees.

In December of 2006, the Company provided preliminary updates to the filing to reflect the impact of the approved 2007 capital expenditure budget. Based on the information provided, the 2007 capital budget for the gas and LNG operations has been reduced from $212,095,000 factored into the filing to $178,790,000. This is a $33,305,000 or 15.7% reduction to the 2007 capital expenditures that were anticipated at the time the filing was prepared by Con Edison.

Q. Has Con Edison provided the impact on its requested rate year revenue requirement resulting from the revision to the 2007 capital expenditure budget?

A. Yes. Revised exhibits provided by Con Edison in December 2006 indicate that revenue requirement should be reduced by $4,299,000 to reflect the various impacts of the revision. The revision impacts not only plant-in-service, but also other items such as accumulated depreciation, depreciation expense and income taxes. On Exhibit__(L&A-1), Schedule 1, we provide the revenue requirement impact that was identified by the Company, a reduction of $4,299,000.

Q. Does it appear that the Company correctly flowed through all of the impacts on its filing resulting from the reduction to the 2007 capital expenditure budget?

A. No, it does not. While the update reflects a $32,329,000 reduction to average plant-in-service, the reduction to depreciation expense is only $119,000. The reduction to depreciation expense resulting from the $32.3 million reduction to the average plant in service balance appears to be significantly understated.

Q. Have you estimated the impact on depreciation expense that would result from the $32.3 million reduction in average rate year plant in service?

A. Yes. The Company's original filing included rate year depreciation expense of $95,963,000 and $3,381,490,000 of average rate year plant-in-service. The resulting average depreciation rate is 2.84% (95,963,000 / $3,381,490,000). Application of the effective average depreciation rate to the revised average plant-in-service balance in the Company's preliminary update results in depreciation expense of $95,046,000 ($3,349,161,000 x 2.84%). This is reduction to the depreciation expense contained in the original filing of $917,000. The reduction included by the Company of $119,000 should be increased by $798,000. We have reflected this additional reduction to depreciation expense on Schedule 1.

Q. Do there appear to be any additional errors in the preliminary update provided by the Company?

A. Yes. In determining the reduction to the 2007 budgeted capital expenditures, the Company compared its Board of Trustees' approved 2007 capital expenditure budget of $178,790,000 to $212,095,000, reflecting a reduction to the 2007 capital expenditure budget of $33,305,000. However, the amount of 2007 capital expenditures shown in the workpapers presented in support of the Company's filing includes an additional $117,000 identified as "Gas Customer Load Characteristics Rate Engineering" and $8,886,000 for the Automated Meter Reading ("AMR") investments. In other words, the 2007 gas and LNG capital expenditures contained in the workpapers and flowing through the filing are $220,098,000 ($212,095,000 + $117,000 + $8,886,000).

Q. Are you recommending an additional adjustment to remove the two items that have not been taken into consideration in the Company's preliminary update?

A. No, not at this time. At this point, we are assuming the project is going forward, although it may be questionable as it was not specifically identified in the update to the 2007 capital expenditure budget. According to the response to CPB5, Question 34, the projected cost savings for the gas operations during the rate year resulting from the AMR system are estimated to be $1.8 million. The Company did not reflect these cost savings in its filing and indicated in the response that these savings will be reflected in its update submittal. At this time, we are reflecting the $1.8 million estimated cost savings on Schedule 1. In the event that these cost savings are not ultimately reflected, the additional capital expenditures contained in the filing for the 2007 AMR capital additions should also be removed.

2008 CAPITAL ADDITIONS

Q. Considering the significant reduction to the 2007 capital expenditure budget resulting from the amount actually approved by the Board of Trustees, did the Company also revise the estimated 2008 capital expenditures contained in the rate year?

A. No, it did not. The original filing factored in projected 2008 capital additions of $256,490,000 for gas distribution and $10,369,000 for LNG plant, resulting in a combined amount of $266,859,000. This is significantly more than the original 2007 capital expenditures contained in the filing of $220,098,000 and also significantly higher than the 2007 capital expenditure budget approved by the Board of Trustees of

$212,095,000. Despite the 15.7% reduction in the 2007 capital expenditure budget, the Company has not updated or likewise reduced its aggressive 2008 capital expenditures budget reflected in the filing.

Q. Are you recommending an adjustment be made to the rate year to reduce the 2008 capital expenditures from the level contained in the filing?

A. Yes, we are. In view of the 15.7% reduction in the 2007 capital expenditure budget, it would be illogical to assume that the 2008 capital expenditure budget would be unaffected. Based on available information, we are recommending a reduction of 15.7% to the $266,859,000 of 2008 projected capital expenditures factored into the filing. In establishing rates in this proceeding, the Commission should consider decisions made by Con Edison's Board of Trustees regarding the 2008 capital budget, if any.

On Exhibit__(L&A-1), Schedule 4, we estimate the impact of the reduction to the 2008 capital expenditures on the average rate year ended September 30, 2008 plant-in-service balance, resulting in a reduction to plant in service of $12,088,000. We applied the average depreciation rate of 2.84% to the reduction, resulting in a $343,000 reduction to rate year depreciation expense. The impact on revenue requirement from these two adjustments is $2,133,000, which is reflected on summary Schedule 1.

Q. Does this complete your prefiled testimony?

A. Yes, it does.

ATTACHMENTS

ATTACHMENT I

Mr. Schultz received a Bachelor of Science in Accounting from Ferris State College in 1975. He maintains extensive continuing professional education in accounting, auditing, and taxation. Mr. Schultz is a member of the Michigan Association of Certified Public Accountants

Mr. Schultz was employed with the firm of Larkin, Chapski & Co., C.P.A.s, as a Junior Accountant, in 1975. He was promoted to Senior Accountant in 1976. As such, he assisted in the supervision and performance of audits and accounting duties of various types of businesses. He has assisted in the implementation and revision of accounting systems for various businesses, including manufacturing, service and sales companies, credit unions and railroads.

In 1978, Mr. Schultz became the audit manager for Larkin, Chapski & Co. His duties included supervision of all audit work done by the firm. Mr. Schultz also represents clients before various state and IRS auditors. He has advised clients on the sale of their businesses and has analyzed the profitability of product lines and made recommendations based upon his analysis. Mr. Schultz has supervised the audit procedures performed in connection with a wide variety of inventories, including railroads, a publications distributor and warehouser for Ford and GM, and various retail establishments.

Mr. Schultz has performed work in the field of utility regulation on behalf of public service commission staffs, state attorney generals and consumer groups concerning regulatory matters before regulatory agencies in Alaska, Arizona, California, Connecticut, Delaware, Florida, Georgia, Kentucky, Kansas, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Dakota, Ohio, Pennsylvania, Rhode Island, Texas, Utah, Vermont and Virginia. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on numerous occasions.

Partial list of utility cases participated in:

U-5331	Consumers Power Co. Michigan Public Service Commission
Docket No. 770491-TP	Winter Park Telephone Co. Florida Public Service Commission

Case Nos. U-5125 and U-5125(R)	Michigan Bell Telephone Co. Michigan Public Service Commission
Case No. 77-554-EL-AIR	Ohio Edison Company Public Utility Commission of Ohio
Case No. 79-231-EL-FAC	Cleveland Electric Illuminating Public Utility Commission of Ohio
Case No. U-6794	Michigan Consolidated Gas Refunds Michigan Public Service Commission
Docket No. 820294-TP	Southern Bell Telephone and Telegraph Co. Florida Public Service Commission
Case No. 8738	Columbia Gas of Kentucky, Inc. Kentucky Public Service Commission
82-165-EL-EFC	Toledo Edison Company Public Utility Commission of Ohio
Case No. 82-168-EL-EFC	Cleveland Electric Illuminating Company, Public Utility Commission of Ohio
Case No. U-6794	Michigan Consolidated Gas Company Phase II, Michigan Public Service Commission
Docket No. 830012-EU	Tampa Electric Company, Florida Public Service Commission
Case No. ER-83-206	Arkansas Power & Light Company, Missouri Public Service Commission
Case No. U-4758	The Detroit Edison Company - (Refunds), Michigan Public Service Commission
Case No. 8836	Kentucky American Water Company, Kentucky Public Service Commission

Case No. 8839	Western Kentucky Gas Company, Kentucky Public Service Commission
Case No. U-7650	Consumers Power Company - Partial and Immediate Michigan Public Service Commission
Case No. U-7650	Consumers Power Company - Final Michigan Public Service Commission
U-4620	Mississippi Power & Light Company Mississippi Public Service Commission
Docket No. R-850021	Duquesne Light Company Pennsylvania Public Utility Commission
Docket No. R-860378	Duquesne Light Company Pennsylvania Public Utility Commission
Docket No. 87-01-03	Connecticut Natural Gas State of Connecticut Department of Public Utility Control
Docket No. 87-01-02	Southern New England Telephone State of Connecticut Department of Public Utility Control
Docket No. 3673-U	Georgia Power Company Georgia Public Service Commission
Docket No. U-8747	Anchorage Water and Wastewater Utility Alaska Public Utilities Commission
Docket No. 8363	El Paso Electric Company The Public Utility Commission of Texas
Docket No. 881167-EI	Gulf Power Company Florida Public Service Commission

Docket No. R-891364	Philadelphia Electric Company Pennsylvania Office of the Consumer Advocate
Docket No. 89-08-11	The United Illuminating Company The Office of Consumer Counsel and the Attorney General of the State of Connecticut
Docket No. 9165	El Paso Electric Company The Public Utility Commission of Texas
Case No. U-9372	Consumers Power Company Before the Michigan Public Service Commission
Docket No. 891345-EI	Gulf Power Company Florida Public Service Commission
ER89110912J	Jersey Central Power & Light Company Board of Public Utilities Commissioners
Docket No. 890509-WU	Florida Cities Water Company, Golden Gate Division Florida Public Service Commission
Case No. 90-041	Union Light, Heat and Power Company Kentucky Public Service Commission
Docket No. R-901595	Equitable Gas Company Pennsylvania Consumer Counsel
Docket No. 5428	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 90-10	Artesian Water Company Delaware Public Service Commission
Docket No. 900329-WS	Southern States Utilities, Inc. Florida Public Service Commission

Case No. PUE900034	Commonwealth Gas Services, Inc. Virginia Public Service Commission
Docket No. 90-1037* (DEAA Phase)	Nevada Power Company - Fuel Public Service Commission of Nevada
Docket No. 5491**	Central Vermont Public Service Corporation Vermont Department of Public Service
Docket No. U-1551-89-102	Southwest Gas Corporation - Fuel Before the Arizona Corporation Commission
	Southwest Gas Corporation - Audit of Gas Procurement Practices and Purchased Gas Costs
Docket No. U-1551-90-322	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. 176-717-U	United Cities Gas Company Kansas Corporation Commission
Docket No. 5532	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 910890-EI	Florida Power Corporation Florida Public Service Commission
Docket No. 920324-EI	Tampa Electric Company Florida Public Service Commission
Docket No. 92-06-05	United Illuminating Company The Office of Consumer Counsel and the Attorney General of the State of Connecticut
Docket No. C-913540	Philadelphia Electric Co. Before the Pennsylvania Public Utility Commission

Docket No. 92-47	The Diamond State Telephone Company Before the Public Service Commission of the State of Delaware
Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation (Supplemental) State of Connecticut Department of Public Utility Control
Docket No. 93-08-06	SNET America, Inc. State of Connecticut Department of Public Utility Control
Docket No. 93-057-01**	Mountain Fuel Supply Company Before the Public Service Commission of Utah
Docket No. 94-105-EL-EFC	Dayton Power & Light Company Before the Public Utilities Commission of Ohio
Case No. 399-94-297**	Montana-Dakota Utilities Before the North Dakota Public Service Commission
Docket No. G008/C-91-942	Minnegasco Minnesota Department of Public Service
Docket No. R-00932670	Pennsylvania American Water Company Before the Pennsylvania Public Utility Commission

Docket No. 12700	El Paso Electric Company Public Utility Commission of Texas
Case No. 94-E-0334	Consolidated Edison Company Before the New York Department of Public Service
Docket No. 2216	Narragansett Bay Commission On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission
Docket No. 2216	Narragansett Bay Commission - Surrebuttal On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission
Case No. PU-314-94-688	U.S. West Application for Transfer of Local Exchanges Before the North Dakota Public Service Commission
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 95-03-01	Southern New England Telephone Company State of Connecticut Department of Public Utility Control
Docket No. U-1933-95-317	Tucson Electric Power Before the Arizona Corporation Commission
Docket No. 5863*	Central Vermont Public Service Corporation Before the Vermont Public Service Board

Docket No. 96-01-26**	Bridgeport Hydraulic Company State of Connecticut Department of Public Utility Control
Docket Nos. 5841/ 5859	Citizens Utilities Company Before Vermont Public Service Board
Docket No. 5983	Green Mountain Power Corporation Before Vermont Public Service Board
Case No. PUE960296**	Virginia Electric and Power Company Before the Commonwealth of Virginia State Corporation Commission
Docket No. 97-12-21	Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 97-035-01	PacifiCorp, dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. G-03493A-98-0705*	Black Mountain Gas Division of Northern States Power Company, Page Operations Before the Arizona Corporation Commission
Docket No. 98-10-07	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 99-01-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-04-18	Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control

Docket No. 99-09-03	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 980007-0013-003	Intercoastal Utilities, Inc. St. John County - Florida
Docket No. 99-035-10	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 6332 **	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket No. G-01551A-00-0309	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. 6460**	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 01-035-01*	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 01-05-19 Phase I	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket No. 010949-EI	Gulf Power Company Before the Florida Office of the Public Counsel
Docket No. 2001-0007-0023	Intercoastal Utilities, Inc. St. Johns County - Florida
Docket No. 6596	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket Nos. R. 01-09-001 I. 01-09-002	Verizon California Incorporated Before the California Public Utilities Commission

Docket No. 99-02-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-04	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 5841/5859	Citizens Utilities Company Before the Vermont Public Service Board
Docket No. 6120/6460	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 020384-GU	Tampa Electric Company d/b/a/ Peoples Gas System Before the Florida Public Service Commission
Docket No. 03-07-02	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 6914	Shoreham Telephone Company Before the Vermont Public Service Board
Docket No. 04-06-01	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket Nos. 6946/6988	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 04-035-42**	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 050045-EI**	Florida Power & Light Company Before the Florida Public Service Commission

Docket No. 050078-EI**	Progress Energy Florida, Inc. Before the Florida Public Service Commission
Docket No. 05-03-17	The Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 05-06-04	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. A.05-08-021	San Gabriel Valley Water Company, Fontana Water Division Before the California Public Utilities Commission
Docket NO. 7120 **	Vermont Electric Cooperative Before the Vermont Public Service Board
Docket No. 7191 **	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 06-035-21 **	PacifiCorp Before the Public Service Commission of Utah
Docket No. 7160	Vermont Gas Systems Before the Vermont Public Service Board
Docket No. 6850/6853 **	Vermont Electric Cooperative/Citizens Communications Company Before the Vermont Public Service Board

* Certain issues stipulated, portion of testimony withdrawn.
** Case settled.

ATTACHMENT II

QUALIFICATIONS OF DONNA DERONNE, C.P.A.

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant and regulatory consultant in the firm of Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I graduated with honors from Oakland University in Rochester, Michigan in 1991. I have been employed by the firm of Larkin & Associates, PLLC, since 1991. As a certified public accountant and regulatory consultant with Larkin & Associates, PLLC, my duties have included the analysis of utility rate cases and regulatory issues, researching accounting and regulatory developments, preparation of computer models and spreadsheets, the preparation of testimony and schedules and testifying in regulatory proceedings. I have also developed and conducted five training programs on behalf of the Department of Defense - Navy Rate Intervention Office on measuring the financial capabilities of firms bidding on Navy assets and one training program on calculating the revenue requirement for municipal owned water and wastewater utilities. A partial listing of cases which I have participated in are included below:

Performed Analytical Work in the Following Cases:

Docket No. 92-06-05	The United Illuminating Company State of Connecticut, Department of Public Utility Control
Docket No. R-00922428	The Pennsylvania American Water Company Pennsylvania Public Utility Commission
Cause No. 39498	PSI Energy, Inc. Before the State of Indiana - Indiana Utility Regulatory Commission
Docket No. 6720-TI-102	Wisconsin Bell, Inc. Wisconsin Citizens' Utility Board
Docket No. 90-1069 (Remand)	Commonwealth Edison, Inc. Before the Illinois Commerce Commission
Docket Nos. 920733-WS & 920734-WS	General Development Utilities, Inc. - Port Labelle and Silver Springs Shores Divisions. Before the Florida Public Service Commission
Case No. PUE910047	Virginia Electric and Power Company (State Corporation Commission)
Docket No. U-1565-91-134	Sun City Water Company Residential Utility Consumer Office
Docket No. 930405-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. UE-92-1262	Puget Sound Power & Light Company Before the Washington Utilities & Transportation Commission
Docket No. R-932667	Pennsylvania Gas & Water Company Before the Pennsylvania Public Utility Commission
Docket No. 7700	Hawaiian Electric Company, Inc. Before the Public Utilities Commission of the State of Hawaii
Docket No. R-00932670	Pennsylvania American Water Company Pennsylvania Public Utility Commission

Case No. 78-T119-0013-94	Guam Power Authority vs. U.S. Navy Public Works Center, Guam - Assisting the Department of Defense in the investigation of a billing dispute.
Case No. 90-256	South Central Bell Telephone Company Before the Kentucky Public Service Commission
Case No. 94-355	Cincinnati Bell Telephone Company Before the Kentucky Public Service Commission
Docket No. 7766	Hawaiian Electric Company, Inc. Before the Public Utilities Commission of the State of Hawaii
Docket No. 2216	Narragansett Bay Commission On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission
Docket No. 94-0097	Citizens Utilities Company, Kauai Electric Division Before the Public Utilities Commission of the State of Hawaii
Docket No. 5863*	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. E-1032-95-433	Citizens Utilities Company - Arizona Electric Division Before the Arizona Corporation Commission
Docket No. R-00973947	United Water Pennsylvania Before the Pennsylvania Public Utilities Commission
Docket No. 95-0051	Hawaiian Storm Damage Reserve Case Before the Public Utilities Commission of the State of Hawaii
Application Nos. 96-08-070, 96-08-071, 96-08-072	Pacific Gas & Electric Company, Southern California Edison Company & San Diego Gas & Electric Co.; Phases I & II; Before the California Public Utilities Commission
Docket No. E-1072-97-067	Southwestern Telephone Company Before the Arizona Corporation Commission
Docket No. 920260-TL	BellSouth Telecommunications Inc. - Florida On Behalf of the Florida Office of Public Counsel

Docket No. R-00973953	PECO Energy Company Before the Pennsylvania Public Utilities Commission
Docket No. 5983	Green Mountain Power Corporation Before the Vermont Public Service Board
Case No. PUE-9602096	Virginia Electric and Power Company Before the Commonwealth of Virginia State Corporation Commission
Docket No. 97-035-01	PacifiCorp, dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. G-34930705	Black Mountain Gas Division - Northern States Power Before the Arizona Corporation Commission
Docket No. T-01051B-99-105*	US West/Qwest Corporation Before the Arizona Corporation Commission
Docket No. 98-10-019	Verizon Audit Report on Behalf of California Office of Ratepayers Advocates
Docket No. 991437-WU*	Wedgefield Utilities, Inc. Before the Florida Public Service Commission
Docket No. 99-057-20*	Questar Gas Company Before the Utah Public Service Commission
Docket No. 6596	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket No. ER02080614	Rockland Electric Company Before the New Jersey Board of Public Service
Docket No. 5841/5859	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Formal Case No. 1016	Washington Gas Light Company Before the Public Service Commission of the District of Columbia
Application No. 02-12-028	San Diego Gas & Electric Company Before the California Public Utilities Commission
Docket No. 03-2035-02**	PacifiCorp - Utah Operations Before the Public Service Commission of Utah

Docket No. 2004-0007-0011-0001	Intercoastal Utilities, Inc. Before the St. Johns County Water & Sewer Authority

Submitted Testimony in the Following Cases

Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Case No. 94-0035-E-42T	Monongahela Power Company Before the Public Service Commission of West Virginia
Case No. 94-0027-E-42T	Potomac Edison Company Before the Public Service Commission of West Virginia
Case No. 95-0003-G-42T*	Hope Gas, Inc. Before the West Virginia Public Service Commission
Case No. 95-0011-G-42T*	Mountaineer Gas Company Before the West Virginia Public Service Commission
Docket No. 950495-WS	Southern States Utilities Before the Florida Public Service Commission
Docket No. 960451-WS	United Water Florida Before the Florida Public Service Commission
Docket No. 5859	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket No. 97-12-21	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control

Docket No. 98-01-02	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 98-07-006	San Diego Gas and Electric Company Public Utilities Commission of the State of California
Docket No. 99-04-18 Phase I	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 99-04-18 Phase II	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 99-09-03 Phase I	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 99-09-03 Phase II	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 99-035-10	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 00-12-01	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 6460*	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 01-035-01*	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. G-01551A-00-0309	Southwest Gas Corporation Arizona Corporation Commission
Docket No. 01-05-19	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket No. 01-035-23 Interim (Oral testimony)	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah

Docket No. 01-035-23**	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 010503-WU	Aloha Utilities, Inc. - Seven Springs Water Division Before the Florida Public Service Commission
Docket No. 000824-EI*	Florida Power Corporation Before the Florida Public Service Commission
Docket No. 001148-EI**	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 01-10-10	United Illuminating Company Connecticut Department of Public Utility Control
Docket No. 02-057-02*	Questar Gas Company Public Service Commission of Utah
Docket No. 020384-GU*	Tampa Electric Company d/b/a Peoples Gas System Before the Florida Public Service Commission
Docket No. 020010-WS	The Woodlands of Lake Placid, L.P. Before the Florida Public Service Commission
Docket No. 020071-WS	Utilities, Inc. of Florida Before the Florida Public Service Commission
Docket No. 03-07-02	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 030438-EI*	Florida Public Utilities Company Before the Florida Public Service Commission
Docket No. 03-11-20	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 030102-WS	The Woodlands of Lake Placid, L.P. Before the Florida Public Service Commission
Docket No. 04-06-01*	Yankee Gas Services Company State of Connecticut, Department of Public Utility Control

Docket No. 6946 & 6988	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 04-035-42*	PacifiCorp Before the Public Service Commission of Utah
Docket No. 050045-EI*	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 05-03-17PH01	The Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 050078-EI*	Progress Energy Florida, Inc. Before the Florida Public Service Commission
Docket No. 05-06-04	The United Illuminating Company State of Connecticut, Department of Public Utility Control
Docket No. A.05-08-021	San Gabriel Valley Water Company, Fontana Water Division Before the California Public Utilities Commission
Case No. 05-E-1222	New York State Electric & Gas Corporation Before the New York Public Service Commission
Docket No. 060038-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 05-11-008*	Southern California Edison Company and San Diego Gas & Electric Company Before the California Public Utilities Commission
Docket No. 06-035-21*	PacifiCorp Before the Public Service Commission of Utah
Docket No. 06-03-04* Phase I	Connecticut Natural Gas Corporation Connecticut Department of Public Utility Control

Application 06-05-025	Request for Order Authorizing the Sale by Thames GmbH of up to 100% of the Common Stock of American Water Works Company, Inc., Resulting in Change of Control of California-American Water Company Before the California Public Utilities Commission
Docket No. U-27703	Atmos Energy Corporation d/b/a Trans Louisiana Gas Company Before the Louisiana Public Service Commission
Case Nos. 06-G-1185 And 06-G-1186	KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island Before the New York Public Service Commission
Docket No. 06-12-02PH01	Yankee Gas Services Company Connecticut Department of Public Utility Control

* Case Settled
** Testimony not filed/submitted due to settlement