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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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APPLICATION OF PENNSYLVANIA	:	
POWER & LIGHT COMPANY FOR	:	
APPROVAL OF ITS RESTRUCTURING	:	
PLAN UNDER SECTION 2806 OF THE	:	DOCKET NO. R-00973954
PUBLIC UTILITY CODE	:	

DIRECT TESTIMONY

OF

LEE SMITH

On Behalf of:

OFFICE OF CONSUMER ADVOCATE

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JULY 1997

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TESTIMONY OF LEE SMITH FOR

PENNSYLVANIA OFFICE OF THE CONSUMER ADVOCATE

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lee Smith, and I work for La Capra Associates, 333 Washington St., Boston, Massachusetts.

Q. WHAT IS YOUR OCCUPATIONAL EXPERIENCE?

A. I am Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 13 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level.

Q. ARE THERE ANY ATTACHMENTS TO THIS TESTIMONY?

A. Yes. A summary of my qualifications and experience is attached at the end of my testimony as Exhibit LS-1, and there are several additional exhibits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on rate design aspects of the restructuring proceeding, including the functionalization of costs, the allocation of costs to rate classes, the resulting unbundling of rates, and the design of an appropriate CTC.

I. Introduction

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED RATE UNBUNDLING?

A. Yes, and in general, I agree with the Company's methods. The Company began by functionalizing its most recent cost allocation study which forms the basis for the current rates of the Company, as presented by the Company's witness, Mr. Kleha. In functionalizing the cost study into the production, transmission and distribution, the Company has appropriately allocated administrative and general ("A&G") expenses, as described by Mr. Kleha in the response to OCA-I-9. This allocation was based on the wages in each function, as a percentage of total wages excluding A&G wages.

Q. HOW DID THE COMPANY TREAT WHOLESALE SALES?

A. According to the Company's witness, Mr. Kleha, the Company allocated its costs between the Federal (wholesale) and Pennsylvania (retail) jurisdictions. The result is that all costs associated with service to Atlantic City Electric Company, Baltimore Gas & Electric Company, Jersey Central Power & Light Company, and UGI Utilities, Inc., plus all full requirements wholesale sales for resale, were excluded from the PUC jurisdictional cost study. It was these remaining costs that were the basis of the Company's unbundled cost of service study.

Q. DO YOU HAVE ANY MODIFICATIONS TO THE COMPANY'S JURISDICTIONAL SPLIT?

A. The Company's fundamental approach is correct. The only modification which I have suggested, which is reflected in the retail stranded cost computation, is that the percentage allocation to wholesale should not change over time for the reasons set forth by OCA witness Richard La Capra.

Q. PLEASE DESCRIBE HOW THE ALLOCATION WAS THEN UTILIZED.

A. The Company designed its delivery rates for T&D services in order to recover the revenue requirement it defined as associated with the transmission, distribution and customer function. Where applicable, the Company included the existing fixed monthly charges in the delivery rates. In the residential Rate RS, the remainder of the revenue requirements were collected in a flat cents per kilowatthour rate.

The Company then developed market-based generation charges, which were based on capacity and energy prices that were presented in the testimony of Dr. Jones. The generation charge is optional for customers desiring to purchase their electric requirements from alternative suppliers. For the Rate RS, for instance, the generation charge was developed using the hourly profile of the class. The generation charges increase with the market prices during the transition period.

Finally, the Company set the Competitive Transition Charge ("CTC") in each year as the residual of the current rates, so that the sum of all three components (delivery, generation and CTC) is equal to the current set of rates. The Company's witness Mr. Krall has testified that the proposed CTC will not collect all of the Company's estimate of its stranded costs over the seven year transition period.

Overall, if calculated correctly, this approach is an appropriate method for unbundling rates. It will ensure that the unbundling is accomplished without shifting costs between the current class allocations, or between customers in the same class, except for some specifics described below. This approach will foster competition in generation, since the optional, avoidable component of the rate is set at the market price of power. It should be noted, however, that the CTC determined by the Company is vastly in excess of what is necessary to collect the proper level of stranded costs, as testified to by Mr. La Capra. I am proposing a levelized CTC that is far below the Company's numbers.

II. Modifications to the PP&L Filing

Q. ARE THERE AREAS OF THE COMPANY'S RATE DESIGN THAT REQUIRE MODIFICATION?

A. Yes, there are a number of the Company's proposals that I believe are incorrect. As noted above, the first change is that the Company's proposed stranded cost estimate is overstated and must be modified as Mr. La Capra recommends. This leads to a number of rate design changes that will be discussed in Section III. Also I do not believe that depreciation reserves should be transferred from T&D to production. The company's proposed "Customized Rate Design" is also a concern. I will also address the proposed treatment of the various incentive rates.

Q. PLEASE EXPLAIN YOUR OBJECTION TO THE COMPANY'S PROPOSED TRANSFER OF $205 MILLION FROM T&D TO PRODUCTION DEPRECIATION RESERVES.

A. The Company's witness Mr. Hill has testified that the Company has proposed to transfer $205 million of accumulated depreciation from the transmission and distribution functions to the production function in order to reduce stranded costs. The effect of this is to increase the T&D revenue requirement and reduce the production revenue requirement.

This adjustment is inappropriate for several reasons. First, this has the effect of shifting cost recovery from generation to the fully regulated retail T&D component. The cost shifting is exacerbated by the different jurisdictional allocation of these different functions. Since 97 percent of the T&D depreciation reserve is allocated to the Pennsylvania jurisdiction, whereas only 81 percent of the production depreciation is allocated to Pennsylvania, the result of this shift of depreciation reserve is a shifting of cost responsibility into the Pennsylvania jurisdiction (see Exhibit LS-2). Although the Company has not made this calculation, a reduction to generation plant of $205 million is only a reduction to the retail jurisdiction of $165 million (80.7 percent of $205 million), but the retail T&D rate base was increased by $198 million (96.7 percent of $205 million). In other words, the stranded cost allocation to Pennsylvania was reduced by less than the T&D rate base was increased. The shift in the depreciation reserve will increase the allocation of costs to the retail jurisdiction.

In addition, the unbundled rates should reflect the existing rates of the Company. Distribution customers have contributed, through rates, the full amount of the accumulated depreciation reserve booked as distribution. To shift this reserve to the generation function will result in distribution customers paying again for the same plant. This also creates a potential for cost shifting between classes.

In order to reverse the depreciation shift made by the Company, I have calculated an annual revenue requirement associated with the reduction in T&D depreciation reserves as calculated by the Company. I assumed that the return on the depreciation reserve component is in the same proportion as on total T&D depreciation reserve, resulting in an annual reduction of $18 million in 1999 for the T&D delivery revenue requirements for the Pennsylvania jurisdiction (see Exhibit LS-2).

Q. PLEASE DESCRIBE THE INCENTIVE RATES.

A. The Company provides Economic Development Initiative (EDI) credits and Industrial Development Initiative (IDI) credits to customers who had signed contracts agreeing to expand production of facilities. The EDI Rider was closed to new customers in 1989 and the IDI credit is open to eligible customers through the end of 1997. The amount of the credit, according to the Tariff Riders, is to be phased out by specified credit reductions in 1998, 1999, and 2000.

Q. WHAT HAS THE COMPANY PROPOSED RELATIVE TO FUTURE TREATMENT OF THE ECONOMIC INCENTIVE RATES?

A. The Company proposes to eliminate the phase-out of the credit and to extend them for current participants through 2005, because phasing them out would increase charges. Customers receiving these credits would be required to purchase generation from PP&L.

Q. WHAT IS YOUR POSITION ON THE TREATMENT OF THE INCENTIVE RATES?

A. The credits should be phased out as scheduled in the tariffs. Also, in the interim, I agree with the Company's treatment of the credits, as described by Mr. Kasper in the response to OCA-II-45. The Company will apply the credits to the energy and capacity portions of the applicable rate schedule. Thus, the customers receiving discount on these programs will be assessed the CTC, the same as any other customer.

Q. DO YOU THINK THAT THE AVERAGE RATE PAID BY CUSTOMERS ON THESE RIDERS MIGHT RISE ABOVE THE CURRENT AVERAGE RATE LEVEL?

A. Because the stranded cost estimation supported by Mr. La Capra results in a low CTC level, I expect that there will be no increase from the current average rate paid by the customers on the EDI and IDI riders. However, while there will be significant decreases to customers on the main commercial and industrial rates, the average rate paid by customers on the incentive rates will show little or no decrease, because they are already paying lower rates, i.e. rates that are close to market rates.

Q. ARE THERE ANY OTHER ASPECTS OF THE COMPANY'S APPROACH TO DIFFERENT RATE CLASSES THAT REQUIRE MODIFICATION?

A. Yes. The Company proposes to continue its Competitive Rate Rider ("CRR"), which would allow it to discount delivery charges and the CTC. It is inappropriate to allow the Company to retain or acquire generation customers by discounting the CTC. This would suggest that if an alternative supplier offered generation service below the market level offered by the Company, the Company could retain the load by discounting the CTC. The new competitive structure should be one in which customers search for the source of generation that they prefer, and the Company cannot influence that choice by discounting the CTC. The CTC must be nonbypassable.

III. Rate Design Issues and Results

Q. HAVE YOU MADE CHANGES TO REFLECT THE ABOVE POSITIONS AND OTHER TESTIMONY OF OCA WITNESSES?

A. Yes. Below I raise some additional rate design issues and present a rate design which takes into account the OCA's market price projection presented by Mr. Smith, and the stranded cost analysis presented by Mr. La Capra.

Q. HAVE YOU CALCULATED THE IMPACT OF THE REDUCTION IN STRANDED COST AND THE INCREASE IN MARKET RATES ON THE RETAIL RATES OF THE COMPANY, BASED ON THE POSITIONS TAKEN BY YOURSELF AND THE OCA'S OTHER WITNESSES IN THESE PROCEEDINGS?

A. Yes. I have started out with the Company's estimate of total T&D revenues and total revenues under the existing rates as proposed by the Company. The Company's proposed unbundled revenue requirements and rates are shown at the top of Exhibit LS-3. I adjusted revenue requirements by the depreciation reserve transfer described above. Then I calculated T&D delivery rates for the revised functional revenue requirements. I calculated a levelized CTC, and also the avoidable generation price. The market price and CTC components were adjusted for the 4.4 percent gross receipts tax in Pennsylvania.

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE COMPETITIVE TRANSITION CHARGE.

A. The estimated stranded cost should be collected on an equal annual basis over the seven year recovery period from 1999 to 2005. This can be accomplished by developing a levelized annual CTC revenue requirement to collect each component of the stranded cost, namely regulatory assets, above-market NUG purchases, nuclear decommissioning, and stranded generating plant.

Q. COULD YOU EXPLAIN HOW THE LEVELIZED REVENUE REQUIREMENT WAS DEVELOPED FOR EACH CLASS?

A. The stranded cost estimate for regulatory assets, which was developed by Mr. Catlin, was calculated by taking the net present value of the annual revenue requirements that the Company would be entitled to collect under traditional ratemaking for each of the assets, discounted at the after-tax weighted average cost of capital of 7.24 percent, as recommended by Mr. La Capra. Mr. Catlin estimated the stranded cost associated with regulatory assets to be $259.2 million. In order to design a CTC revenue requirement that allows the Company to recover this stranded cost over the seven year transition period, the net present value of the CTC revenue requirement must also equal $259.2 million when discounted at the 7.24 percent rate. I have computed this requirement to be approximately $48.5 million per year over the seven year period.

The stranded cost estimate for NUG purchases was developed using the same method as that used to determine the CTC for regulatory assets. The net present value of the CTC revenue requirement associated with above-market NUG contracts must equal the estimated stranded cost of $550.95 million when discounted at 7.24 percent. The resulting levelized annual CTC revenue requirement is $103.088 million.

The stranded cost estimate for nuclear decommissioning was calculated by taking the net present value of the annual decommissioning fund contributions to be made by PUC jurisdictional customers over the life of each plant. However, we have determined a CTC that will allow these costs to be recovered over a seven year period, consistent with the Act. There is no need to spread these costs over the life of the nuclear units, as proposed by the Company. Taking into account the projected earnings rate for the decommissioning trust funds that were used by PP&L, the equivalent annual decommissioning fund contribution over the seven year period for PUC jurisdictional customers would be $19.959 million. This annual number is the CTC revenue requirement associated with decommissioning.

Finally, the estimated stranded cost for the Company's generating assets was a negative $535.7 million (i.e., the estimated market value of the assets exceeds the net book value as of January 1, 1999 by this amount). Since customers have paid for this plant, the market value of which is greater than the book value, it is appropriate to credit this value against the annual CTC revenue requirements associated with the other stranded cost categories. This effectively reduces the annual CTC revenue requirement associated with other categories by $100.24 million annually over the seven year period. This treatment nets Company assets with positive value against those with negative value.

In summary, the total annual CTC revenue requirement over the seven year period, which will provide for equitable recovery of the stranded costs associated with regulatory assets, NUG purchases, nuclear decommissioning, and stranded generating plant, should be $71 million. The computation of this amount is shown in Exhibit LS-4 .

Q. ARE THERE ANY OTHER RATE DESIGN ISSUES WHICH YOU WOULD LIKE TO ADDRESS?

A. While the Company has allocated Universal Service costs to all customer classes, it has allocated these costs on the basis of numbers of customers. This means that the largest industrial customer pays exactly as much to support Universal Service as does the smallest residential customer who is not on Universal Service. As stated in the testimony of OCA witness Ms. Brockway, it would be more appropriate to allocate these costs on a basis that reflects customer usage. This adjustment should be included in the final rate design in this case.

Q. PLEASE DESCRIBE HOW THE CTC HAS BEEN CALCULATED?

A. The CTC calculation began with the annual levelized CTC amount of $71.315 million, as described above. This amount was increased to $74.597 to include the gross receipts tax. This total was divided by the annual retail kilowatthour sales, resulting in an average CTC rate of .23 cents per kwh in 1999. Since projected retail sales increase throughout the transition period, the annual CTC decreases slightly, to .21 cents in 2005.

Q. PLEASE DESCRIBE HOW THE AVOIDABLE GENERATION PRICE IS DEVELOPED.

A. I began with the market price projections at the generation level for capacity and energy as presented by Mr. Smith. Rates at the customer level will be higher than Mr. Smith's values because of both line losses and differences in class load shapes. For instance, an all hours market price is calculated for load that would be flat over every hour of the year, which is not true of any class. I adjusted the market prices for energy and capacity to reflect prices at the customer level, by assuming the same relationship that the Company has used to go from market prices to customer level prices. I applied the ratios of the Company's estimate of its customer-level prices to the generation-level energy and capacity prices presented by Dr. Jones (see Exhibit LS-page 2). I also made an adjustment, also using PP&L ratios, for the difference between residential and average retail market prices.

The adjusted market price of power will understate the cost of getting generation to customers by the amount of administrative and general costs that will be required to market, aggregate load, reconcile load and supply, deal with PJM, write contracts, and all the activities that will be required to get power to customers. These costs are all part of the avoidable cost of energy. Either PP&L or alternative suppliers will provide the services that these costs represent to customers purchasing generation. I have estimated these costs from generation A&G in the cost of service study, based on the assumption that pensions and benefits and insurance are more closely related to on-going production costs, and that other A&G belonged in this avoidable generation component. I excluded the insurance and pensions and benefits expense, which continue to be counted as a going-forward cost to be subtracted from market revenues. The avoidable A&G is an amount that must be added to the retail spot cost of power. Avoidable generation cost calculations are shown in Exhibit LS-5.

Q. HAVE YOU CALCULATED THE IMPACT OF THE REDUCTION IN STRANDED COST AND THE INCREASE IN MARKET RATES ON THE RETAIL RATES OF THE COMPANY, BASED ON THE AVERAGE SYSTEM UNBUNDLED RATES WHICH YOU DESCRIBED ABOVE

A. Yes. The result is an average rate decrease in 1999 of 32 percent. In each subsequent year the decrease is smaller, so that by 2005 the rate reduction is only 7 percent. In 2006 the CTC will be eliminated, but the expected increase in the market price will probably be larger than the CTC that was eliminated, so customers will see little if any rate change.

Q. HAVE YOU PROJECTED THE RESIDENTIAL RATE RS FOR 1999?

A. Yes. I have adjusted the Company's proposed delivery rates in a similar fashion to the total retail rate analysis described in the previous answer . The CTC amount was allocated to the class on the basis of the generation capacity allocator, and rate design followed the process described for the retail system as a whole. This results in a decrease of 28 percent in 1999, as shown in Exhibit LS-5, page 1.

Q. ARE THERE ANY OTHER RATE ISSUES?

A. Yes. The Company has proposed a Customized Rate Design ("CRD"), in which half of its CTC charges are collected through customer charges based on individual customer usage in calendar year 1996. The Company is proposing that the CRD be mandatory for all classes except for residential customers, who would have the choice of two rate designs. The Company called the residential option the "traditional rate design", and this rate in total is the same as the current Rate RS, in each rate component. Thus, many of PP&L's customers would have a uniquely determined customer charge, which would remain fixed during the transition period.

Q. WHAT ARE THE PROBLEMS WITH THE PROPOSED CRD?

A. First, there is no basis for the Company's claim that this is a more efficient rate design. The Company's witness Dr. Tierney has said that it is more efficient, since there are no marginal costs associated with stranded costs (see response to OCA-II-36). However, neither Dr. Tierney nor any other Company witness presented a full marginal cost study, including the transmission and distribution functions. Without a marginal cost study we cannot determine whether a partially fixed CTC is actually consistent with an efficient total rate design. The marginal cost of T&D may be higher than the embedded revenue requirement; in this case, a flat T&D charge and a fixed CTC may not signal to customers the full cost of marginal usage.

Second, the proposed design shifts stranded cost responsibility from customers who increase their usage, thereby resulting in a promotional rate design. This is because a portion of the stranded cost recovery is fixed rather than usage-dependent. If usage remains the same, then there is no effective difference in the two rate designs. If customers increase their usage, the customized rate design produces a decrease in the total bill compared to the standard rate design.

This can be illustrated by comparing the customized rate to the traditional rate for residential customers, as shown in Exhibit LS-6. The first two sets of comparisons show the Company's rates for customers using 1,000 and 500 kwh per bill during the transition period. The third set of comparisons shows that for customers increasing their usage, then the customized rate design yields rates that are 8 percent lower in 2005. But for customers who decrease their usage, the customized option is 14 percent higher than the traditional rate option. Thus, the customized rate design favors customer growth and would discourage usage reducing options. While the examples presented here are intended to be illustrative, they are meaningful in that there are residential customer options that can result in changes of this magnitude, for example the installation or removal of equipment for electric water heating or more efficient electric space conditioning.

For these reasons, the Commission should disallow the Company's proposed Customized Rate Design. Instead, the Commission should order the Company to design all of its rates in the traditional format.

Q. PP&L ARGUES THAT IT WILL NOT BE ABLE TO COLLECT ITS STRANDED COST DURING THE SEVEN YEAR PERIOD, AND THAT IT SHOULD BE ALLOWED TO EXTEND THE PERIOD. DO YOU HAVE ANY COMMENTS ON THIS APPROACH?

A. Yes. Given the level of the stranded cost that Mr. La Capra has recommended, the Company will be able to collect its stranded costs within the seven year transition period. If stranded costs could not be collected within the seven year period, any extension of the recovery period should be conditioned on the Company's agreement to extend the generation rate cap by an equivalent period.

Q. ARE THERE ANY OTHER ISSUES OF CONCERN WITH REGARD TO THE RECONCILIATION OF STRANDED COST?

A. Yes. Even though the stranded cost values which we have developed are low, I do not think that the reconciliation process should be able to shift some cost responsibility onto certain customer classes. This would be the case, for instance, if in spite of the Company's attempt to identify sales lost due to additional self-generation, the industrial load paying the CTC decreased. It could also result from changes in load shape in the demand-metered classes. The Company might also in the future award economic development discounts to its largest customers in order to retain load. In all of these instances, stranded cost collection could decrease. If the reconciliation is done on a class-specific basis, this problem would be avoided. In other words, the 1997 class allocation of CTC costs would be applied in the reconciliation process. This could result in some classes finishing CTC collection before others.

Q. WHAT DO YOU RECOMMEND WITH REGARD TO RECONCILIATION OF THE CTC?

A. The problems that I have identified can be addressed by reconciling CTC collection on a class basis. That is, the each class would be held responsible for paying the share of total CTC collection determined in this class.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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LEE SMITH

EDUCATION

TUFTS UNIVERSITY, all but dissertation for Ph.D., Economics
BOSTON COLLEGE, Study of Statistics
BROWN UNIVERSITY, Bachelor of Arts with Honors, International Relations and Economics

Experience

1984-	LA CAPRA ASSOCIATES Senior Economist Ms. Smith's work has encompassed all costing issues, forecasting, rate design, demand and supply planning regarding electric and gas utilities. Ms. Smith has extensive experience in testifying and negotiating.
1982-84	Department of Public Utilities; Director of Rates and Research
1981-82	Department of Public Utilities; Economist, Long-Run Planning
1978-79	REGIS COLLEGE, Lecturer in Economics
1974-77	MERRIMACK COLLEGE, Lecturer in Economics
1973-74	UNIVERSITY OF MARYLAND, Faculty Research Associate
1972-73	TUFTS UNIVERSITY, Lecturer in Economics
1967	FEDERAL RESERVE BANK of Boston, Administrative Assistant, Research Department
1965-66	FEDERAL RESERVE BANK, Research Assistant, Banking and Regional Policy

Publications:

Non-price Issues in Gas Supply Planning, NATIONAL REGULATORY RESEARCH INSTITUTE, Biennial Regulatory Research Conference, 1994

The Economic Impact of Hurricane Agnes on the Chesapeake Bay in Maryland, JOHN HOPKINS PRESS

Papers:

"Development and Implementation of Restructuring in New England", Institute of Public Utilities at Michigan State University Williamsburg Conference, December 1995

"Planning for Gas and Electric Reliability", NARUC Biennial Regulatory Information Conference, Vol. II, 1994

"The Economic Impact of Hurricane Agnes on the Chesapeake Bay in Maryland", JOHN HOPKINS PRESS

Honors:

Bunting Institute Fellowship, 1970-71
Tufts University Economics Department Fellowship, 1967-68
Brown University International Relations Prize, 1965

Description of Selected Projects

1997	Maryland/Pennsylvania Public Advocates
	Advising staff of both public advocates on PJM restructuring, including analysis of FERC filings and ongoing development of market structures and ISO.
1997	Massachusetts Division of Energy Resources
	Assisting DOER in drafting restructuring legislation and negotiating additional restructuring settlements with utilities
1997	Pennsylvania Office of the Consumer Advocate
	Assisting Commission staff in both electricity restructuring cases and utility requests for Qualified Rate Orders allowing securitization of some stranded costs.
1997	Osram Sylvania
	Negotiating transportation rate and revised gas sales tariff for large industrial; providing advice about process of selecting electric generation supplier.
1997	Essex County Gas Company
	Developing planning standards and 5-year demand forecast for Company use and for submission to the Energy Facilities Siting Board.
1996	New Hampshire Public Utilities Commission
	Assisted Commission staff in writing Draft Order on Restructuring; prepared discovery for utilities; prepared discovery questions for hearings on various issues, including corporate unbundling, market structure, transmission, stranded cost theory, measurement, and mitigation.
1996	Blackstone Gas Company
	Prepared rate case and negotiated settlement; negotiated special contracts for sales and transportation of gas.
1996	Massachusetts Division of Energy Resources

Represented the DOER at NEPOOL committees engaged in developing an Independent System Operator, a revised NEPOOL Agreement, and an Open Access Transmission Tariff for New England. Assisted the DOER in other matters including development of model for Boston Edison pilot program based on proxy for competitive market real-time pricing.

1996 CMEEC

Developed methodologicalbasis for rate unbundling for the five Connecticut municipal utilities that are members of CMEEC.

1995 Black Hills Power and Light Company (South Dakota)

Advised Company on development of ancillary services and open access transmission rates.

1995 Pennsylvania Office of the Consumer Advocate

Assisted with preparation of comments on restructuring issues

1995 Maine Office of the Public Advocate

Prepared alternative marginal cost study on Maine Public Service Company. Presented testimony advocating allocation of excess costs on the basis of generation allocators rather than EPMC.

1995 Massachusetts Division of Energy Resources

Assisted DOER in all aspects of electric industry restructuring, from rate unbundling to planning and developing revised market structure for the New England Power Pool.

1995 Littleton Water and Light Department (N.H.)

Developed retail wheeling rate; advised on retail wheeling policy issues

1995 Kansas Citizens' Utility Ratepayers Board

Prepared testimony on cost allocation and rate design for local gas distribution utility. Assisted in settlement negotiations.

1995 Boston Edison Company

Presented rate design workshop for Company personnel to assist in preparing for restructuring.

1995 World Bank

Developing conditions under which State of Orissa, which is privatizing its electric distribution system, should consider revaluation; assisting with other restructuring issues.

1994 Division of Energy Resources

Advised DOER on position on changes in Integrated Resource Management, including proposal to open Transmission and Distribution access to meet resource needs.

1994 Black Hills Power and Light Company (South Dakota)

Advised Company on rate treatment and phase-in of major new generating unit, development of wholesale transmission rate, and response to retail wheeling.

1994 New Hampshire Office of the Consumer Advocate

Advised Office on retail wheeling concerns; prepared testimony on cost of service, cost allocation and marginal cost presented by an electric utility.

1994 Massachusetts Municipal Wholesale Electric Company

Testified for MMWEC on appropriate allocation of gas transition costs; assisted MMWEC in formulating response to generic docket on interruptible gas transportation; prepared comments.

1994 Town of Fort Fairfield

Prepared response of town to CMP's threat to shut down a renewable energy facility following state-financed buyout of a high-priced unit contract, resulting in settlement.

1994 Blackstone Gas Company

Formulated plan for settlement of long-term debt with Tennessee Gas Pipeline Company; gained approval for long-term debt financing.

1993 North Attleborough Gas Company

Revised long-run econometric forecast of load, assisted Company in preparation of supply/demand forecast for DPU.

1994 Constellation Energy

Projected market price of power, advised developer on potential market.

1994 Stow Electric Energy Study Committee

Advised committee on setting up new municipal utility, based upon results of response to RFP for provision of power and operations services, negotiated with bidders.

1993 Massachusetts Department of Energy Resources;

Assisted with analysis of economic impact of retiring older generating plants to meet Clear Air Act Targets.

1993 Eastern Energy Associates

Directed analysis and computation of avoided costs of a major electric utility.

1993 Blackstone Gas Company

Issued RFP, planned gas supply, negotiated supply contracts for small gas LDC.

1993 Maine Public Utility Commission Staff

Directed Staff's case in opposition to Central Maine Power Comp.'s request that it be allow to market power at below marginal cost rates; presented testimony on impact of CMP's proposal.

1993 Essex County Gas

Advised Company on long-run planning issues; developed innovative approach to reliability planning standards; directed full Demand and Supply Forecast which has been submitted to the Massachusetts Energy Facilities Siting Board.

1993 North Attleborough Gas Company

Directed development of long-run econometric forecast of load by type of customer.

1993 Office of the People's Counsel, Washington D.C.

Advised Office, presented testimony on appropriate recovery of deferred and present costs of ongoing Least Cost Planning program, including $10 million in expenses of conservation programs.

1993 Plattsburgh Municipal Lighting Department

Advised utility on selection of least-cost power contracts.

1993 Wakefield Municipal Light Department

Presented testimony on gas distribution systems, transportation pricing issues in Boston Gas Company rate case.

1993 Nantucket Electric Company

Directed development of long-run end-use load forecast for tourism-based economy.

1992 Massachusetts Municipal Wholesale Electric Company

Analysis of and testimony on economic inefficiencies created by Bay State pricing of interruptible gas to Stony Brook generating unit.

1992 Woodsville Water and Light Department

Advised Department on least-cost power supply and led negotiations with potential suppliers, resulting in significant long-run savings.

1992 Stow Electric Energy Study Committee

Advised Committee on advisability of separating from municipal electric system currently serving the town; analyzed costs and benefits of different sources of supply.

1992 Boston Edison Electric Company

Assisted in analysis of customer's demand for experimental color-corrected streetlighting, resulting in settlement of long-standing dispute.

1992	Plattsburgh Municipal Light Department
	Prepared rate case, including revenue needs, allocation of costs, and rate design; directed Company in reorganization of billing data.
1992	Colonial Gas Company
	Directed analysis of company's new pipeline transportation contract with ANE (Iroquois); tested cost-effectiveness, analyzed non-pricing contract attributes.
1992	North Attleborough Gas Company
	Presented Company rate filing, including reconciliation of actual year experience with predictions of previous settlement.
1992	Altresco
	Advised on siting, fuel costs, and bidding of potential new intermediate power project.
1992	Middleton Electric Light Department
	Renegotiation of contract for transmission of all power to the utility.
1992	Nantucket Electric Company
	Directed revision of load research sampling (determining appropriate sample size and selection)
1991	Colonial Gas Company
	Assisted in development of Conservation and Load Management Plan, including development of avoided gas supply and distribution costs.
1991	Essex County Gas
	Prepared rate designs, testified in rate case on Company's marginal costs and rates; developed long-run avoided costs, including externalities, for use in screening Demand Side Measures.
1991	Massachusetts Electric Company
	Prepared testimony for fuel switching case which analyzed marginal cost of

Boston Gas Company, comparability of marginal cost estimation of electric and gas utilities.

1991 North Attleborough Gas Company

Assisted Company in all phases of filing rate case, including testimony and settlement negotiations, development of three new rate classes, and in developing strategy for phasing in very large (over 100%) increase in rate base.

1991 Nantucket Electric Company

Applied load research data to develop detailed (daily) demand and revenue projections.

1991 Nantucket Electric Company

Assisted in rate case, including allocating costs between customer classes, developing marginal costs, designing rates.

1991 Essex County Gas Company

Assisted Company in filing rate case, including development of labor allocator and other allocations, marginal cost analysis, rate design; prepared avoided cost for use in DSM program screening.

1991 Nantucket Electric Company

Presented testimony on externalities created by emissions from electric generation on Nantucket Island, and potential impact of inclusion of externalities on ratepayers.

1991 Blackstone Gas Company

Prepared full rate case (first filed by the Company in 9 years); presented testimony, assisted in a settlement of the case with intervenors.

1990 Wakefield Municipal Light Department

Assisted gas division of WMLD with avoiding hundreds of thousands of rate increase from Boston Gas Company; presented testimony on errors in Boston Gas filing; analyzed distribution system of both utilities.

1990 Illinois Office of Public Counsel

Provided expert advice to consumer advocate group on developing state least-cost planning guidelines for gas utilities.

1990 Berkshire Gas Company

Assisted company with development of a pilot DSM program, including directing the development of the screening tools, estimating long-run avoided costs based on daily dispatch of Company proposed supply portfolio, then in screening cost-effective measures.

1990 Plattsburgh Municipal Light Department

Developed new rate for large, 46 KV service customers, directed development of value of plant serving the proposed class.

1990 Colonial Gas Company

Assisted Company in developing various analyses for rate case, including converting class sales data (which includes a billing lag) to weather-adjusted, calendar data for use in revenue normalization and rate purposes. Refined La Capra Associates cost allocation model and trained company personnel in use of model.

1990 Blackstone Gas Company

Resolved long-run undercollection of gas costs; assisted company in negotiations with its major lender, developed long-run plan to resolve inappropriate debt.

1990 Mobile Gas Service Corporation

Assisted Company in development of strategy with regard to marketing plan in which electric company made payments to customers and appliance dealers to cause customers to switch to electric heat; directed detailed analysis of marginal costs and benefits of the electric marketing program.

1989 Middleton Electric Light Department

Developed innovative cost-based rate for very large interruptible customer and negotiated with both NEPOOL and customer.

1989 Berkshire Gas Company

Assisted Company in EFSC case, performing both innovative demand and supply analyses. We demonstrated that improved methodologies showed that new pipeline contract was beneficial to ratepayers.

1989 Littleton Water and Light Department

Updated Company's revenue allocation and rates to reflect new marginal-cost based wholesale power tariff.

1989 Wakefield Municipal Light Department

Advised company regarding gas supply planning; assisted in renegotiation of contract with Boston Gas Company.

1989 Essex County Gas Company

Assisted with all aspects of rate case filing, including revenue estimation, cost allocation, and rate design, introducing subsidized rates for low-income customers.

1989 Colonial Gas Company

Designed rates in rate case filing; reorganized commercial and industrial rate classes.

1989 Boston Edison Company

Assisted Company in analysis of jurisdictional cost allocations in major court dispute; developed company response to FERC order on allocation of distribution/transmission plant.

1988 Reading Municipal Light Department

Analyzed power supply options, determined least-cost options.

1987 Essex County Gas Company

Assisted with all aspects of rate case filing, including revenue estimation, cost allocation, and rate design. This case moved rates closer to seasonal marginal costs, and class revenues closer to allocated costs. Modified Company's existing dispatch model to produce additional results for rate case and planning purposes, developed model to estimate marginal distribution costs.

1987 Wellesley Municipal Light Plant

Redesigned rates for municipal utility, including allocating costs, estimating marginal costs, and designing rates, including a time-of-use rate for largest customers.

1986 Colonial Gas Company

Redesigned Company rates according to allocated cost of service study, marginal cost principles.

1985 Colonial Gas Company

Developed daily gas dispatch model to simulate actual daily dispatch, calculate marginal gas costs by season, and allocate gas costs between users.

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Exhibit LS–2

Depreciation Reserve Adjustment

Jurisdictional Allocation of Depreciation Reserves (Note a)

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	Total PP&L	PA Jurisdiction	PA %
Production	1,731,642	1,396,759	80.66%
Transmission	142,010	116,155	81.79%
Distribution	874,812	867,290	99.14%
Total T&D	1,016,822	983,445	96.72%

Jurisdictional Allocation of $205 Million Transfer

	Total PP&L	PA Jurisdiction	PA %
Production	(205,000)	(165,355)	80.66%
T&D	205,000	198,271	96.72%

Rate RS Class Allocation of $205 Million Transfer (Note b)

	Total PA	Rate RS	RS %
Trans Depreciation Reserve	116,155	44,759	38.53%
Trans Return	9.83%	7.67%	
Dep Res Rev Req	11,418	3,433	30.07%
Dist Depreciation Reserve	741,913	460,135	62.02%
Dist Return	8.74%	7.61%	
Dep Res Rev Req	64,843	35,016	54.00%
T&D Depreciation Reserve	858,068	504,894	58.84%
T&D Combined Return	8.89%	7.62%	
T&D Dep Res Rev Req	76,261	38,449	50.42%
T&D Rate Base Decrease	198,271	116,664	58.84%
T&D Combined Return	8.89%	7.62%	
T&D Rev Req Decrease	17,621	8,884	50.42%

a) Source: Exhibit JMK–1 page 12, 34.
b) Source: Exhibit JMK–2 for T&D depreciation reserves and returns.

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Exhibit LS-3

Unbundled Average Retail Rates For PP&L

	1999	2000	2001	2002	2003	2004	2005
Unbundled Revenue Per PP&L (Note a)							
T&D Delivery	$580,343	$587,907	$596,141	$605,415	$613,874	$620,237	$627,769
CTC	$949,269	$877,701	$776,061	$686,529	$664,095	$643,910	$652,248
Energy & Capacity	$966,168	$1,065,368	$1,197,150	$1,319,921	$1,371,868	$1,418,887	$1,439,223
Total Rate Revenue	$2,495,780	$2,530,975	$2,569,352	$2,611,865	$2,649,837	$2,683,034	$2,719,239
Unbundled Average Rates Per PP&L							
MWh	33,090,377	33,581,491	34,104,641	34,688,679	35,228,379	35,707,385	36,224,091
T&D Delivery/kWh	0.0175	0.0175	0.0175	0.0175	0.0174	0.0174	0.0173
CTC/kWh	0.0287	0.0261	0.0228	0.0198	0.0189	0.0180	0.0180
Energy & Cap/kWh	0.0292	0.0317	0.0351	0.0381	0.0389	0.0397	0.0397
Total Rev/kWh	0.0754	0.0754	0.0753	0.0753	0.0752	0.0751	0.0751
Adjustments Per OCA							
Reverse Dep Reserve (Note b)	$18,432	$18,706	$18,997	$19,322	$19,623	$19,890	$20,178
T&D After Adjustment	$561,911	$569,201	$577,144	$586,093	$594,251	$600,347	$607,591
Market Rev Per OCA	$1,002,943	$1,150,001	$1,328,965	$1,407,352	$1,511,102	$1,596,013	$1,776,815
A&G Adder	$59,196	$58,084	$57,394	$59,391	$60,888	$62,885	$64,879
Stranded Cost Per OCA	$74,597	$74,597	$74,597	$74,597	$74,597	$74,597	$74,597
Total After Adjustments	$1,698,647	$1,851,883	$2,038,100	$2,127,434	$2,240,839	$2,333,842	$2,523,883
Unbundled Average Rates Per OCA							
T&D Delivery/kWh	0.0170	0.0169	0.0169	0.0169	0.0169	0.0168	0.0168
Market/kWh	0.0303	0.0342	0.0390	0.0406	0.0429	0.0447	0.0491
A&G Adder/kWh	0.0018	0.0017	0.0017	0.0017	0.0017	0.0018	0.0018
CTC/kWh	0.0023	0.0022	0.0022	0.0022	0.0021	0.0021	0.0021
Total Rev/kWh	0.0513	0.0551	0.0598	0.0613	0.0636	0.0654	0.0697
Difference (OCA–PP&L)	($797,132)	($679,092)	($531,252)	($484,431)	($408,998)	($349,192)	($195,357)
Percentage Change	−32%	−27%	−21%	−19%	−15%	−13%	−7%

a) Source: OCA–III–39 Attachment 1.
b) Reverse of depreciation reserve includes GRT.

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Exhibit LS-4, page 1

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)

Summary

Year	*Stranded* Generating Plant	Regulatory Assets	Above-Market NUG Purchases	Nuclear Decommissioning	*Total* Annual Rev. Req.
1999	($100,240)	$48,508	$103,088	$19,959	$71,315
2000	($100,240)	$48,508	$103,088	$19,959	$71,315
2001	($100,240)	$48,508	$103,088	$19,959	$71,315
2002	($100,240)	$48,508	$103,088	$19,959	$71,315
2003	($100,240)	$48,508	$103,088	$19,959	$71,315
2004	($100,240)	$48,508	$103,088	$19,959	$71,315
2005	($100,240)	$48,508	$103,088	$19,959	$71,315
NPV @7.24%	($535,730)	$259,249	$550,951	$106,672	$381,142

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)
Stranded Generating Plant

Year	Stranded Net Plant	Accum. Deferred Taxes	Base for Return	Return @ 7.24%	Annual Amort.	Levelized Annual Rev. Req.
1999	($535,730)	$0	($535,730)	($38,787)	($61,453)	($100,240)
2000	($474,277)	$0	($474,277)	($34,338)	($65,902)	($100,240)
2001	($408,375)	$0	($408,375)	($29,566)	($70,673)	($100,240)
2002	($337,702)	$0	($337,702)	($24,450)	($75,790)	($100,240)
2003	($261,912)	$0	($261,912)	($18,962)	($81,277)	($100,240)
2004	($180,634)	$0	($180,634)	($13,078)	($87,162)	($100,240)
2005	($93,472)	$0	($93,472)	($6,767)	($93,472)	($100,240)

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)
Regulatory Assets

Year	Balance of Regulatory Assets	Base for Return	Return @ 7.24%	Annual Amort.	Levelized Annual Rev. Req.
1999	$259,249	$259,249	$18,770	$29,738	$48,508
2000	$229,511	$229,511	$16,617	$31,891	$48,508
2001	$197,620	$197,620	$14,308	$34,200	$48,508
2002	$163,420	$163,420	$11,832	$36,676	$48,508
2003	$126,744	$126,744	$9,176	$39,332	$48,508
2004	$87,412	$87,412	$6,329	$42,179	$48,508
2005	$45,233	$45,233	$3,275	$45,233	$48,508
				NPV @7.24% =	$259,249

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)
Above-Market NUG Purchases & Buyout Costs

Year	Balance of Above-Market NUG Purchases	Base for Return	Return @ 7.24%	Annual Amort.	Levelized Annual Rev. Req.
1999	$550,951	$550,951	$39,889	$63,199	$103,088
2000	$487,752	$487,752	$35,313	$67,774	$103,088
2001	$419,978	$419,978	$30,406	$72,681	$103,088
2002	$347,296	$347,296	$25,144	$77,943	$103,088
2003	$269,353	$269,353	$19,501	$83,587	$103,088
2004	$185,766	$185,766	$13,449	$89,638	$103,088
2005	$96,128	$96,128	$6,960	$96,128	$103,088
				NPV @7.24% =	$550,951

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)
Nuclear Decommissioning Costs

Year	Decom. Fund Susq. Unit 1	Decom. Fund Susq. Unit 2	Decom. Fund Susq. Total	PUC Jurisdictional Percentage	Levelized Annual Rev. Req.
1999	$9,627	$15,813	$25,440	78.456%	$19,959
2000	$9,627	$15,813	$25,440	78.456%	$19,959
2001	$9,627	$15,813	$25,440	78.456%	$19,959
2002	$9,627	$15,813	$25,440	78.456%	$19,959
2003	$9,627	$15,813	$25,440	78.456%	$19,959
2004	$9,627	$15,813	$25,440	78.456%	$19,959
2005	$9,627	$15,813	$25,440	78.456%	$19,959

Proposed Rate RS (1999)

Current Rate	Rate	Billing Units	Revenue
Customer Charge	$6.47	13,337,538	$86,293,871
First 200 kWh	$0.08845	2,468,108,629	$218,304,208
Next 200 kWh	$0.07847	4,861,770,271	$381,503,113
Excess kWh	$0.07248	4,302,650,225	$311,856,088
Total	$0.08579	11,632,529,125	$997,957,281

OCA Proposed Rate	Rate	Billing Units	Revenue
T&D Delivery:			
Customer Charge	$6.47	13,337,538	$86,293,871
First 200 kWh	$0.01885	2,468,108,629	$46,514,660
Next 200 kWh	$0.01885	4,861,770,271	$91,626,270
Excess kWh	$0.01885	4,302,650,225	$81,088,939
Total	$0.02626	11,632,529,125	$305,523,740
Avoidable Generation:			
First 200 kWh	$0.03325	2,468,108,629	$82,066,754
Next 200 kWh	$0.03325	4,861,770,271	$161,658,082
Excess kWh	$0.03325	4,302,650,225	$143,066,855
Total	$0.03325	11,632,529,125	$386,791,691
CTC (Note a):			
First 200 kWh	$0.00278	2,468,108,629	$6,857,037
Next 200 kWh	$0.00246	4,861,770,271	$11,983,191
Excess kWh	$0.00228	4,302,650,225	$9,795,546
Total	$0.00246	11,632,529,125	$28,635,774
Total Rate:			
Customer Charge	$6.47	13,337,538	$86,293,871
First 200 kWh	$0.05488	2,468,108,629	$135,438,451
Next 200 kWh	$0.05456	4,861,770,271	$265,267,544
Excess kWh	$0.05437	4,302,650,225	$233,951,340
Total		11,632,529,125	$720,951,205
Difference (OCA – PP&L)			($277,006,075)
Percentage Change			–28%

a) CTC allocation to Rate RS per prod allocator, Exhibit JMK–2:

Total CTC w GRT	$74,597,280
Rate RS Allocation	38.39%
Rate RS CTC	$28,635,774

Derivation of Market Price

	1999	2000	2001	2002	2003	2004	2005
PP&L Market Price							
Capacity ($/kW)	$22.00	$29.00	$38.00	$50.00	$49.00	$48.00	$44.00
Energy ($/MWh)	$22.00	$23.00	$24.00	$24.00	$25.00	$26.00	$26.00
All Hours Capacity	$2.51	$3.31	$4.34	$5.71	$5.59	$5.48	$5.02
All-hours ($/MWh)	$24.51	$26.31	$28.34	$29.71	$30.59	$31.48	$31.02
PP&L Rate RS Market Price (OCA-III-39)							
Capacity/kWh	0.00586	0.00772	0.01012	0.01332	0.01305	0.01278	0.01172
Energy/kWh	0.02381	0.02472	0.02597	0.02618	0.02715	0.02822	0.02888
Capacity/MWh	5.86	7.72	10.12	13.32	13.05	12.78	11.72
Energy/MWh	23.81	24.72	25.97	26.18	27.15	28.22	28.88
Capacity Multiplier (Rate RS)	2.333	2.332	2.333	2.334	2.333	2.332	2.333
Capacity Energy (Rate RS)	1.082	1.075	1.082	1.091	1.086	1.085	1.111
PP&L Total Retail Market Price							
Per Response to OCA-III-39	$29.20	$31.72	$35.10	$38.05	$38.94	$39.74	$39.73
Rate RS/Total Retail Ratio	1.0162	1.0225	1.0281	1.0381	1.0323	1.0318	1.0219
OCA Market Price							
Capacity ($/kW)	$19.73	$30.43	$41.67	$43.12	$44.20	$45.66	$47.12
Energy ($/MWh)	$22.35	$23.61	$25.14	$26.38	$28.14	$29.42	$31.84
All Hours Capacity	$2.25	$3.47	$4.76	$4.92	$5.05	$5.21	$5.38
All-hours ($/MWh)	$24.60	$27.08	$29.90	$31.30	$33.19	$34.63	$37.22
OCA Rate RS Market Price	0.0294	0.0335	0.0383	0.0403	0.0423	0.0441	0.0479
OCA Total Retail Market Price	0.0290	0.0327	0.0373	0.0388	0.0410	0.0427	0.0469
OCA RS Incl GRT	0.0308	0.0350	0.0401	0.0421	0.0443	0.0461	0.0501
OCA Total Retail Incl GRT	0.0303	0.0342	0.0390	0.0406	0.0429	0.0447	0.0491

Derivation of A&G in Market Price

	1999	2000	2001	2002	2003	2004	2005
A&G Per PP&L ($ Million)	$154	$152	$150	$155	$159	$164	$169
Generation Fraction	66.10%	66.10%	66.10%	66.10%	66.10%	66.10%	66.10%
Generation A&G	$102	$100	$99	$102	$105	$108	$112
Fraction in rates (1 – .4455)	55.45%	55.45%	55.45%	55.45%	55.45%	55.45%	55.45%
Generation A&G in Rates	$57	$56	$55	$57	$58	$60	$62
Gross–up for GRT	$59	$58	$57	$59	$61	$63	$65
Residential A&G Allocation Factor	48.18%						
Residential Allocation	$29						

Exhibit LS–6

Comparison of Traditional and Customized Rate Options
For Residential Customers
Source: PP&L Response to OCA Set II, Q. 38

Case 1: Usage at 1,000 kWh throughout:

Year	1999	2000	2001	2002	2003	2004	2005
Usage	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Traditional	$85.74	$85.74	$85.74	$85.74	$85.74	$85.74	$85.74
Customized	$85.73	$85.73	$85.73	$85.73	$85.73	$85.73	$85.73
% Difference	–0%	–0%	–0%	–0%	–0%	–0%	–0%

Case 2: Usage at 500 kWh throughout:

Usage	500	500	500	500	500	500	500
Traditional	$47.70	$47.70	$47.70	$47.70	$47.70	$47.70	$47.70
Customized	$47.70	$47.70	$47.70	$47.70	$47.70	$47.70	$47.70
% Difference	0%	0%	0%	0%	0%	0%	0%

Case 3: Usage increasing from 500 kWh to 1,000 kWh:

Usage	500	600	700	800	900	1000	1000
Traditional	$47.70	$55.55	$63.40	$71.24	$78.49	$85.74	$85.74
Customized	$47.70	$54.09	$59.66	$66.86	$72.95	$79.04	$79.04
% Difference	0%	–3%	–6%	–6%	–7%	–8%	–8%

Case 4: Usage decreasing from 1,000 kWh to 500 kWh:

Usage	1000	900	800	700	600	500	500
Traditional	$85.74	$78.49	$71.24	$63.40	$55.55	$47.70	$47.70
Customized	$85.73	$79.64	$73.55	$67.17	$60.78	$54.39	$54.39
% Difference	–0%	1%	3%	6%	9%	14%	14%

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OCA STATEMENT NO. 4-S

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R-973954

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PENNSYLVANIA POWER & LIGHT COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	:	DOCKET NO. R-00973954

SURREBUTTAL TESTIMONY

OF

LEE SMITH

On Behalf of:
OFFICE OF CONSUMER ADVOCATE

AUGUST 1997

SURREBUTTAL TESTIMONY OF LEE SMITH FOR PENNSYLVANIA OFFICE OF THE CONSUMER ADVOCATE

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lee Smith, and I work for La Capra Associates, 333 Washington Street, Boston, Massachusetts 02108.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes. I previously submitted direct testimony on behalf of the Pennsylvania Office of the Consumer Advocate. My qualifications and experience are presented in that testimony.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY.

A. I will update some of the exhibits in my original testimony for the new market prices developed by Mr. Smith and the new stranded cost developed by Mr. La Capra. I intend to respond to the testimony of PP&L's witnesses Dr. Tierney, Mr. Krall and Mr. Kasper, and of the Industrial Customer Alliance's witness, Mr. Baron. I will discuss the design of the Competitive Transition Charge ("CTC"); the Company's proposed Customized Rate Design ("CRD"); and the Company's proposed treatment of the economic incentive rates.

Q. PLEASE EXPLAIN THE CHANGES TO YOUR ORIGINAL EXHIBITS DUE TO THE UPDATED ANALYSES OF MESSRS. LA CAPRA AND SMITH.

A. I have recomputed the levelized CTC as shown in Exhibits LS-7 and LS-8. Exhibit LS-7 is based on Mr. La Capra's stranded cost estimate in Exhibit RLC-7 using the Fall 96/Winter 97 DRI Fuel forecast; and Exhibit LS-8 is based on Mr. La Capra's recommended stranded cost estimate shown in Exhibit RLC-8 using the DRI Spring 97 fuel forecast. These exhibits are updates of Exhibit LS-4 in my original testimony. After adjusting the CTC for the Pennsylvania gross receipts tax, Mr. La Capra's recommended stranded cost estimate results in a levelized CTC which has increased from approximately $75 million in my original testimony to $205 million in each year of the transition period. I have also updated the market price at the customer level as shown in Exhibit LS-9, which is an updated version of Exhibit LS-5, page 2.

CTC Design

Q. IN YOUR PREFILED TESTIMONY ON PAGES 9 THROUGH 12, YOU DESCRIBE YOUR PROPOSED METHOD OF CALCULATING THE CTC FOR PP&L AS A LEVELIZED AMOUNT OVER THE SEVEN YEAR TRANSITION PERIOD. HAVE YOU RECONSIDERED YOUR PROPOSAL?

A. Yes. I have examined the effect of four different CTC collection strategies, as shown in Exhibit LS-10. The top example shows my original proposal, in which the CTC of approximately $205 million is collected in equal amounts over the transition period. The reduction from revenues at current rates begins at 24 percent in the first year, and ends at a 3 percent increase in the last year. However, the annual change from the prior year, which is how customers would perceive rate changes, begins with a 24 percent reduction, and then increases annually at rates varying from 2 to 10 percent.

The second example shows a method in which the CTC is tailored so as to yield an equal reduction from current rates in all years of the transition period. Under this method, customers would see an initial reduction of 10 percent, and then no change in rates from the prior year for the duration of the transition period. However, this would result in an initial CTC of $561 million, which would decrease to a negative $147 million in the last year. This is because the market costs increase by $858 million during the transition period, and the total CTC collection is small in comparison. While I might prefer this method in principle because of the rate impacts, I do not think that this is a practical alternative for PP&L. I think that a large negative CTC rate component in the latter years would cause customer confusion.

The third example shows PP&L's preferred alternative. PP&L's witness, Dr. Tierney, recommended an approach in which PP&L would be allowed to collect "as fully as possible under the rate cap" (rebuttal testimony, page 23). Since the stranded cost collection recommended by Mr. La Capra is relatively small in comparison to the current rates, the

Company could recover the full amount in the first two years. This example shows that there would be no change in the first year, an 11 percent reduction in year 2, and an 8 percent reduction in year 3, followed by increases ranging from 3 to 6 percent.

The last example shows a blend of the first two methods, in which each method is weighted so that the CTC decreases, but does not become negative. This results in an initial decrease of 16 percent in the first year, followed by increases ranging from 1 to 4 percent in the latter years.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR THE DESIGN OF THE CTC.

A. As mentioned above, I prefer the equal percentage reduction (the second example above). However, it is not a practical alternative here. In its stead, I recommend the fourth approach, in which the CTC declines over time, but moderates the increases as much as possible.

I have updated my prior exhibits for these changes. Exhibit LS-11 is an updated version of Exhibit LS-3 and shows my proposed average retail rates for the Company. Exhibit LS-12 is an updated version of Exhibit LS-5, page 1 and shows my proposal for the residential rate RS.

Efficiency of Customized Rate Design

Q. IN YOUR PREFILED TESTIMONY, YOU OBJECTED TO THE COMPANY'S "CUSTOMIZED RATE DESIGN", AND RECOMMENDED THAT ALL RATES BE BASED ON THE "TRADITIONAL RATE DESIGN", THAT IS, THE CURRENT RATE DESIGN. DO YOU STAND BY THIS RECOMMENDATION?

A. Yes. I opposed the Customized Rate Design because first, there was no demonstration that CRD is more efficient than the traditional approach; and second, because it results in promotional rates favoring customers who increase their usage and penalize customers who decrease their usage.

The Company's witnesses have disputed my findings, but have not presented any evidence which supports its claims.

Q. PLEASE DISCUSS THE EFFICIENCY CLAIMS OF THE COMPANY.

A. Dr. Tierney argues on page 34 of her rebuttal testimony that "even without a marginal cost study, it is possible to conclude that the total non-bypassable usage charges ... exceed the Company's marginal costs. It is well known that most of the variable costs of energy use are attributable to the production function. Similarly, it is well known that embedded transmission and distribution costs are largely fixed costs which do not vary with energy use."

However, I disagree with Dr. Tierney's assertions, and think that the opposite is true. It has been my experience in general that the marginal cost of T&D is greater than the embedded cost of T&D. This is because the cost of transmission and distribution facilities has been increasing over time, so that the cost of new facilities is greater than existing facilities, which can remain in service over many decades. Also, there have not been radical new technologies which result in decreasing costs.

System planners must size transmission and distribution facilities to serve the expected peak load on the system. Increases in peak demands will necessitate the building of upgraded or new facilities to serve the higher loads. System planners are constantly monitoring the performance of T&D equipment to ensure that adequate capacity is in place.

In contrast, the marginal cost of generation is often less than the embedded cost of supply. This is because new facilities can come on line at lesser cost than existing facilities. This is particularly true of utilities with expensive nuclear generation.

Q. HAVE YOU EVALUATED THE MARGINAL COST OF T&D FACILITIES FOR THE PP&L SYSTEM?

A. No, I have not evaluated the marginal cost of new T&D facilities on the Company's system. However, I would expect that the marginal cost of T&D is greater than the embedded cost, which is 1.75 cents per kilowatthour as shown in Exhibit LS-3 to my original testimony. Pennsylvania utilities have not adopted marginal cost based rate design, but in states that have, it is the practice to include marginal T&D in the design of rates. This is true in particular of Massachusetts, where Dr. Tierney served as Commissioner of the Department of Public Utilities. Indeed, Dr. Tierney has signed orders for electric utility rate cases in which a full assessment of marginal costs including T&D was used in rate design (e.g. MDPU 89-255 for Western Massachusetts Electric Company and MDPU 88-135/151, Commonwealth Electric Company).

Q. PLEASE DISCUSS THE COMPANY'S ARGUMENTS CONCERNING THE SHIFTING OF CTC RESPONSIBILITY FROM CUSTOMERS WHO DECREASE USAGE TO CUSTOMERS WHO INCREASE THEIR USAGE.

A. Dr. Tierney denies that there is a shifting of CTC responsibility, as does another Company witness, Mr. Krall on page 11 of his rebuttal testimony. This is simply incorrect. This can best be illustrated by the examples shown in Dr. Tierney's Exhibit SFT-14. This exhibit shows that a customer who reduces consumption from 9,000 to 6,000 kWh would pay $123.58 under the traditional rate, but $153.58 on the customized rate. Likewise, the exhibit shows that a customer who increases consumption from 9,000 to 12,000 kWh would pay $243.58 on the traditional rate, but only $213.58 on the customized rate. Thus, the customer who increases usage pays less and the customer who decreases usage pays more on the customized rate.

Q. PLEASE SUMMARIZE YOUR OPINION OF THE COMPANY'S CUSTOMIZED RATE DESIGN.

A. I urge the Commission to disallow the Company's proposed Customized Rate Design. Essentially, the Company has proposed a radical change in which the tail blocks in the rates are reduced. This decrease in tail blocks is clearly promotional and shifts CTC responsibility from customers who increase usage to customers who conserve energy. Since there is no evidence on the record as to whether these reduced tail blocks cover the Company's incremental cost of supply, the Commission should reject the Company's proposal.

Economic Incentive Rates

Q. WHAT HAS THE COMPANY PROPOSED RELATIVE TO FUTURE TREATMENT OF THE ECONOMIC INCENTIVE RATES?

A. The Company proposes to eliminate the phase-out of the credit and to extend them for current participants through 2005, because phasing them out would increase charges. Customers receiving these credits would be required to purchase generation from PP&L.

Q. WHAT IS YOUR POSITION ON THE TREATMENT OF THE INCENTIVE RATES?

A. The credits should be phased out as scheduled in the tariffs. Also, in the interim, I agree with the Company's treatment of the credits, as described by Mr. Kasper in the response to OCA-II-45. The Company will apply the credits to the energy and capacity portions of the applicable rate schedule. Thus, the customers receiving discounts on these programs will be assessed the CTC, the same as any other customer.

Q. DO YOU THINK THAT THE AVERAGE RATE PAID BY CUSTOMERS ON THESE RIDERS MIGHT RISE ABOVE THE CURRENT AVERAGE RATE LEVEL?

A. Because the stranded cost estimation supported by Mr. La Capra results in a low CTC level, I expect that there will be no increase from the current average rate paid by the customers on the EDI and IDI riders. However, while there will be significant decreases to customers on the main commercial and industrial rates, the average rate paid by customers on the incentive rates will show little or no decrease, because they are already paying lower rates, i.e. rates that are close to market rates.

Q. ARE THERE ANY OTHER ASPECTS OF THE COMPANY'S APPROACH TO DIFFERENT RATE CLASSES THAT REQUIRE MODIFICATION?

A. Yes. The Company proposes to continue its Competitive Rate Rider ("CRR"), which would allow it to discount delivery charges and the CTC. It is inappropriate to allow the Company to retain or acquire generation customers by discounting the CTC. This would suggest that if an alternative supplier offered generation service below the market level offered by the Company, the Company could retain the load by discounting the CTC. The new competitive structure should be one in which customers search for the source of generation that they prefer, and the Company cannot influence that choice by discounting the CTC. The CTC must be nonbypassable.

Q. MR. BARON CRITICIZES MY PROPOSAL THAT THE COMPANY NOT BE ALLOWED TO CONTINUE ITS COMPETITIVE RATE RIDER ON THE GROUNDS THAT THIS WOULD VIOLATE THE RATE CAP. DO YOU AGREE?

A. Mr. Baron misinterprets my position. I understand that customers who are on a low rate essentially have a lower stranded cost amount currently in their rates. Customers on the EDI and IDI riders are paying tariffed rates with a discount schedule which calls for phasing out the discount. It would be inappropriate to lock in the current level of discount. With regard to the CRR customers, current customers who are paying lower than standard rates are paying lower than standard stranded costs.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)

Summary

** Based on Stranded Cost Estimate from Exhibit RLC-7*

Year	Stranded Generating Plant	Regulatory Assets	Above-Market NUG Purchases	Nuclear Decommissioning	Total Annual Rev. Req.
1999	($74,632)	$48,508	$105,449	$19,959	$99,284
2000	($74,632)	$48,508	$105,449	$19,959	$99,284
2001	($74,632)	$48,508	$105,449	$19,959	$99,284
2002	($74,632)	$48,508	$105,449	$19,959	$99,284
2003	($74,632)	$48,508	$105,449	$19,959	$99,284
2004	($74,632)	$48,508	$105,449	$19,959	$99,284
2005	($74,632)	$48,508	$105,449	$19,959	$99,284
NPV @7.24%	($398,871)	$259,249	$563,572	$106,672	$530,622

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Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)

Stranded Generating Plant

** Based on Stranded Cost Estimate from Exhibit RLC-7*

Year	Stranded Net Plant	Accum. Deferred Taxes	Base for Return	Return @ 7.24%	Annual Amort.	Levelized Annual Rev. Req.
1999	($398,871)	***$0***	($398,871)	($28,878)	($45,754)	($74,632)
2000	($353,117)	***$0***	($353,117)	($25,566)	($49,067)	($74,632)
2001	($304,050)	***$0***	($304,050)	($22,013)	($52,619)	($74,632)
2002	($251,431)	***$0***	($251,431)	($18,204)	($56,429)	($74,632)
2003	($195,003)	***$0***	($195,003)	($14,118)	($60,514)	($74,632)
2004	($134,489)	***$0***	($134,489)	($9,737)	($64,895)	($74,632)
2005	($69,594)	***$0***	($69,594)	($5,039)	($69,594)	($74,632)

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)

Regulatory Assets

** Based on Stranded Cost Estimate from Exhibit RLC-7*

Year	Balance of Regulatory Assets	Base for Return	Return @ 7.24%	Annual Amort.	Levelized Annual Rev. Req.
1999	$259,249	$259,249	$18,770	$29,738	$48,508
2000	$229,511	$229,511	$16,617	$31,891	$48,508
2001	$197,620	$197,620	$14,308	$34,200	$48,508
2002	$163,420	$163,420	$11,832	$36,676	$48,508
2003	$126,744	$126,744	$9,176	$39,332	$48,508
2004	$87,412	$87,412	$6,329	$42,179	$48,508
2005	$45,233	$45,233	$3,275	$45,233	$48,508
				NPV @7.24% =	$259,249

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)
Above-Market NUG Purchases & Buyout Costs
** Based on Stranded Cost Estimate from Exhibit RLC-7*

Year	Balance of Above-Market NUG Purchases	Base for Return	*Return @* 7.24%	Annual Amort.	Levelized Annual Rev. Req.
1999	$563,572	$563,572	$40,803	$64,647	$105,449
2000	$498,925	$498,925	$36,122	$69,327	$105,449
2001	$429,598	$429,598	$31,103	$74,346	$105,449
2002	$355,252	$355,252	$25,720	$79,729	$105,449
2003	$275,523	$275,523	$19,948	$85,501	$105,449
2004	$190,022	$190,022	$13,758	$91,692	$105,449
2005	$98,330	$98,330	$7,119	$98,330	$105,449
				NPV @7.24% =	$563,572

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)

Nuclear Decommissioning Costs

** Based on Stranded Cost Estimate from Exhibit RLC-7*

Year	Decom. Fund Susq. Unit 1	Decom. Fund Susq. Unit 2	Decom. Fund Susq. Total	PUC Jurisdictional Percentage	Levelized Annual Rev. Req.
1999	$9,627	$15,813	$25,440	78.456%	$19,959
2000	$9,627	$15,813	$25,440	78.456%	$19,959
2001	$9,627	$15,813	$25,440	78.456%	$19,959
2002	$9,627	$15,813	$25,440	78.456%	$19,959
2003	$9,627	$15,813	$25,440	78.456%	$19,959
2004	$9,627	$15,813	$25,440	78.456%	$19,959
2005	$9,627	$15,813	$25,440	78.456%	$19,959

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)

Summary

** Based on Stranded Cost Estimate from Exhibit RLC-8*

Year	Stranded Generating Plant	Regulatory Assets	Above-Market NUG Purchases	Nuclear Decommissioning	Total Annual Rev. Req.
1999	$19,732	$48,508	$107,533	$19,959	$195,731
2000	$19,732	$48,508	$107,533	$19,959	$195,731
2001	$19,732	$48,508	$107,533	$19,959	$195,731
2002	$19,732	$48,508	$107,533	$19,959	$195,731
2003	$19,732	$48,508	$107,533	$19,959	$195,731
2004	$19,732	$48,508	$107,533	$19,959	$195,731
2005	$19,732	$48,508	$107,533	$19,959	$195,731
NPV @7.24%	$105,455	$259,249	$574,708	$106,672	$1,046,084

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Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)
Stranded Generating Plant

** Based on Stranded Cost Estimate from Exhibit RLC-8*

Year	Stranded Net Plant	Accum. Deferred Taxes	Base for Return	Return @ 0.00%	Annual Amort.	Levelized Annual Rev. Req.
1999	$138,121	$34,856	$103,265	$0	$19,732	$19,732
2000	$118,389	$29,877	$88,513	$0	$19,732	$19,732
2001	$98,658	$24,897	$73,760	$0	$19,732	$19,732
2002	$78,926	$19,918	$59,008	$0	$19,732	$19,732
2003	$59,195	$14,938	$44,256	$0	$19,732	$19,732
2004	$39,463	$9,959	$29,504	$0	$19,732	$19,732
2005	$19,732	$4,979	$14,752	$0	$19,732	$19,732

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)

Regulatory Assets

** Based on Stranded Cost Estimate from Exhibit RLC-8*

Year	Balance of Regulatory Assets	Base for Return	Return @ 7.24%	Annual Amort.	Levelized Annual Rev. Req.
1999	$259,249	$259,249	$18,770	$29,738	$48,508
2000	$229,511	$229,511	$16,617	$31,891	$48,508
2001	$197,620	$197,620	$14,308	$34,200	$48,508
2002	$163,420	$163,420	$11,832	$36,676	$48,508
2003	$126,744	$126,744	$9,176	$39,332	$48,508
2004	$87,412	$87,412	$6,329	$42,179	$48,508
2005	$45,233	$45,233	$3,275	$45,233	$48,508
				NPV @7.24% =	$259,249

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)
Above-Market NUG Purchases & Buyout Costs

** Based on Stranded Cost Estimate from Exhibit RLC-8*

Year	Balance of Above-Market NUG Purchases	Base for Return	Return @ 7.24%	Annual Amort.	Levelized Annual Rev. Req.
1999	$574,708	$574,708	$41,609	$65,924	$107,533
2000	$508,784	$508,784	$36,836	$70,697	$107,533
2001	$438,087	$438,087	$31,718	$75,815	$107,533
2002	$362,272	$362,272	$26,228	$81,304	$107,533
2003	$280,967	$280,967	$20,342	$87,191	$107,533
2004	$193,777	$193,777	$14,029	$93,503	$107,533
2005	$100,273	$100,273	$7,260	$100,273	$107,533
				NPV @7.24% =	$574,708

Pennsylvania Power & Light

Annual CTC Revenue Requirements ($000)

Nuclear Decommissioning Costs

** Based on Stranded Cost Estimate from Exhibit RLC-8*

Year	Decom. Fund Susq. Unit 1	Decom. Fund Susq. Unit 2	Decom. Fund Susq. Total	PUC Jurisdictional Percentage	Levelized Annual Rev. Req.
1999	$9,627	$15,813	$25,440	78.456%	$19,959
2000	$9,627	$15,813	$25,440	78.456%	$19,959
2001	$9,627	$15,813	$25,440	78.456%	$19,959
2002	$9,627	$15,813	$25,440	78.456%	$19,959
2003	$9,627	$15,813	$25,440	78.456%	$19,959
2004	$9,627	$15,813	$25,440	78.456%	$19,959
2005	$9,627	$15,813	$25,440	78.456%	$19,959

Exhibit LS-9
(Updates Exhibit LS-5, page 2)

Derivation of Market Price

	1999	2000	2001	2002	2003	2004	2005
PP&L Market Price							
Capacity ($/kW)	$22.00	$29.00	$38.00	$50.00	$49.00	$48.00	$44.00
Energy ($/MWh)	$22.00	$23.00	$24.00	$24.00	$25.00	$26.00	$26.00
All Hours Capacity	$2.51	$3.31	$4.34	$5.71	$5.59	$5.48	$5.02
All-hours ($/MWh)	$24.51	$26.31	$28.34	$29.71	$30.59	$31.48	$31.02
PP&L Rate RS Market Price (OCA-III-39)							
Capacity/kWh	0.00586	0.00772	0.01012	0.01332	0.01305	0.01278	0.01172
Energy/kWh	0.02381	0.02472	0.02597	0.02618	0.02715	0.02822	0.02888
Capacity/MWh	5.86	7.72	10.12	13.32	13.05	12.78	11.72
Energy/MWh	23.81	24.72	25.97	26.18	27.15	28.22	28.88
Capacity Multiplier (Rate RS)	2.333	2.332	2.333	2.334	2.333	2.332	2.333
Capacity Energy (Rate RS)	1.082	1.075	1.082	1.091	1.086	1.085	1.111
PP&L Total Retail Market Price							
Per Response to OCA-III-39	$29.20	$31.72	$35.10	$38.05	$38.94	$39.74	$39.73
Rate RS/Total Retail Ratio	1.0162	1.0225	1.0281	1.0381	1.0323	1.0318	1.0219
OCA Market Price							
Capacity ($/kW)	$19.72	$30.36	$41.66	$42.84	$44.13	$45.57	$47.08
Energy ($/MWh)	$23.89	$26.09	$28.99	$30.40	$32.12	$33.44	$35.27
All Hours Capacity	$2.25	$3.47	$4.76	$4.89	$5.04	$5.20	$5.37
All-hours ($/MWh)	$26.14	$29.56	$33.75	$35.29	$37.16	$38.64	$40.64
OCA Rate RS Market Price	0.0311	0.0361	0.0425	0.0446	0.0466	0.0484	0.0517
OCA Total Retail Market Price	0.0306	0.0353	0.0413	0.0429	0.0452	0.0469	0.0506
OCA RS Incl GRT	0.0325	0.0378	0.0444	0.0466	0.0488	0.0507	0.0541
OCA Total Retail Incl GRT	0.0320	0.0370	0.0432	0.0449	0.0473	0.0491	0.0529

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Exhibit LS-10

Alternative CTC Methods For PP&L

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Example 1: Levelized method CTC

	PTD	CTC	Total Per OCA	Rate ¢/kWh	Rate Change From Prior Year	Total @ Current	Change (OCA-Current) /(Current)
1999	1,680,731	204,740	1,885,471	5.70	-24%	2,495,780	-24%
2000	1,868,211	204,740	2,072,951	6.17	8%	2,530,975	-18%
2001	2,107,963	204,740	2,312,702	6.78	10%	2,569,352	-10%
2002	2,203,507	204,740	2,408,246	6.94	2%	2,611,865	-8%
2003	2,319,867	204,740	2,524,607	7.17	3%	2,649,837	-5%
2004	2,416,326	204,740	2,621,065	7.34	2%	2,683,034	-2%
2005	2,590,164	204,740	2,794,904	7.72	5%	2,719,239	3%
NPV Rate							
0.0724	11,379,111	1,094,228	12,473,339			13,885,412	-10%

Example 2: Levelized Percentage Decrease

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	PTD	CTC	Total	Rate ¢/kWh	Rate Change From Prior Year	Total @ Current	Reduction (Current-OCA) /(Current)
1999	1,680,731	561,241	2,241,972	6.78	-10%	2,495,780	-10%
2000	1,868,211	405,377	2,273,588	6.77	-0%	2,530,975	-10%
2001	2,107,963	200,100	2,308,063	6.77	-0%	2,569,352	-10%
2002	2,203,507	142,746	2,346,253	6.76	-0%	2,611,865	-10%
2003	2,319,867	60,495	2,380,362	6.76	-0%	2,649,837	-10%
2004	2,416,326	(6,143)	2,410,183	6.75	-0%	2,683,034	-10%
2005	2,590,164	(147,457)	2,442,707	6.74	-0%	2,719,239	-10%
0.0724	11,379,111	1,094,228	12,473,339			13,885,412	-10%

Example 3: Front-Loaded Method

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	PTD	CTC	Total	Rate ¢/kWh	Rate Change From Prior Year	Total @ Current	Reduction (Current-OCA) /(Current)
1999	1,680,731	815,048	2,495,780	7.54	0%	2,495,780	0%
2000	1,868,211	384,350	2,252,561	6.71	-11%	2,530,975	-11%
2001	2,107,963		2,107,963	6.18	-8%	2,569,352	-18%
2002	2,203,507		2,203,507	6.35	3%	2,611,865	-16%
2003	2,319,867		2,319,867	6.59	4%	2,649,837	-12%
2004	2,416,326		2,416,326	6.77	3%	2,683,034	-10%
2005	2,590,164		2,590,164	7.15	6%	2,719,239	-5%
0.0724	11,379,111	1,094,228	12,473,339			13,885,412	-10%

Example 4: Weighted Examples 1 & 2

	PTD	CTC	Total	Rate ¢/kWh	Rate Change From Prior Year	Total @ Current	Reduction
		42.0%					
1999	1,680,731	411,510	2,092,242	6.32	-16%	2,495,780	-16%
2000	1,868,211	321,109	2,189,321	6.52	3%	2,530,975	-13%
2001	2,107,963	202,049	2,310,011	6.77	4%	2,569,352	-10%
2002	2,203,507	168,783	2,372,290	6.84	1%	2,611,865	-9%
2003	2,319,867	121,078	2,440,945	6.93	1%	2,649,837	-8%
2004	2,416,326	82,428	2,498,754	7.00	1%	2,683,034	-7%
2005	2,590,164	465	2,590,630	7.15	2%	2,719,239	-5%
0.0724	11,379,111	1,094,228	12,473,339			13,885,412	-10%

Exhibit LS-11
(Updates Exhibit LS-3)

Unbundled Average Retail Rates For PP&L

	1999	2000	2001	2002	2003	2004	2005
Unbundled Revenue Per PP&L (Note a)							
T&D Delivery	$580,343	$587,907	$596,141	$605,415	$613,874	$620,237	$627,769
CTC	$949,269	$877,701	$776,061	$686,529	$664,095	$643,910	$652,248
Energy & Capacity	$966,168	$1,065,368	$1,197,150	$1,319,921	$1,371,868	$1,418,887	$1,439,223
Total Rate Revenue	$2,495,780	$2,530,975	$2,569,352	$2,611,865	$2,649,837	$2,683,034	$2,719,239
Unbundled Average Rates Per PP&L							
MWh	33,090,377	33,581,491	34,104,641	34,688,679	35,228,379	35,707,385	36,224,091
T&D Delivery/kWh	0.0175	0.0175	0.0175	0.0175	0.0174	0.0174	0.0173
CTC/kWh	0.0287	0.0261	0.0228	0.0198	0.0189	0.0180	0.0180
Energy & Cap/kWh	0.0292	0.0317	0.0351	0.0381	0.0389	0.0397	0.0397
Total Rev/kWh	0.0754	0.0754	0.0753	0.0753	0.0752	0.0751	0.0751
Adjustments Per OCA							
Reverse Dep Reserve (Note b)	$18,432	$18,706	$18,997	$19,322	$19,623	$19,890	$20,178
T&D After Adjustment	$561,911	$569,201	$577,144	$586,093	$594,251	$600,347	$607,591
Market Rev Per OCA	$1,059,624	$1,240,926	$1,473,425	$1,558,022	$1,664,728	$1,753,094	$1,917,694
A&G Adder	$59,196	$58,084	$57,394	$59,391	$60,888	$62,885	$64,879
Stranded Cost Per OCA	$411,510	$321,109	$202,049	$168,783	$121,078	$82,428	$465
Total After Adjustments	$2,092,242	$2,189,321	$2,310,011	$2,372,290	$2,440,945	$2,498,754	$2,590,630
Unbundled Average Rates Per OCA							
T&D Delivery/kWh	0.0170	0.0169	0.0169	0.0169	0.0169	0.0168	0.0168
Market/kWh	0.0320	0.0370	0.0432	0.0449	0.0473	0.0491	0.0529
A&G Adder/kWh	0.0018	0.0017	0.0017	0.0017	0.0017	0.0018	0.0018
CTC/kWh	0.0124	0.0096	0.0059	0.0049	0.0034	0.0023	0.000[illegible]
Total Rev/kWh	0.0632	0.0652	0.0677	0.0684	0.0693	0.0700	0.0715
Difference (OCA-PP&L)	($403,538)	($341,654)	($259,341)	($239,575)	($208,892)	($184,280)	($128,610)
Percentage Change	-16%	-13%	-10%	-9%	-8%	-7%	-5%

a) Source: OCA-III-39 Attachment 1.
b) Reverse of depreciation reserve includes GRT.

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Exhibit LS-12
(Updates Exhibit LS-5, page 1)

Proposed Rate RS (1999)

Current Rate	**Rate**	**Billing Units**	**Revenue**
Customer Charge	$6.47	13,337,538	$86,293,871
First 200 kWh	$0.08845	2,468,108,629	$218,304,208
Next 200 kWh	$0.07847	4,861,770,271	$381,503,113
Excess kWh	$0.07248	4,302,650,225	$311,856,088
Total	$0.08579	11,632,529,125	$997,957,281
OCA Proposed Rate	**Rate**	**Billing Units**	**Revenue**
T&D Delivery:			
Customer Charge	$6.47	13,337,538	$86,293,871
First 200 kWh	$0.01885	2,468,108,629	$46,514,660
Next 200 kWh	$0.01885	4,861,770,271	$91,626,270
Excess kWh	$0.01885	4,302,650,225	$81,088,939
Total	$0.02626	11,632,529,125	$305,523,740
Avoidable Generation:			
First 200 kWh	$0.03499	2,468,108,629	$86,362,803
Next 200 kWh	$0.03499	4,861,770,271	$170,120,595
Excess kWh	$0.03499	4,302,650,225	$150,556,150
Total	$0.03499	11,632,529,125	$407,039,548
CTC (Note a):			
First 200 kWh	$0.01533	2,468,108,629	$37,826,327
Next 200 kWh	$0.01360	4,861,770,271	$66,104,367
Excess kWh	$0.01256	4,302,650,225	$54,036,385
Total	$0.01358	11,632,529,125	$157,967,079
Total Rate:			
Customer Charge	$6.47	13,337,538	$86,293,871
First 200 kWh	$0.06916	2,468,108,629	$170,703,789
Next 200 kWh	$0.06743	4,861,770,271	$327,851,232
Excess kWh	$0.06640	4,302,650,225	$285,681,475
Total		11,632,529,125	$870,530,367
Difference (OCA - PP&L)			($127,426,913)
Percentage Change			-13%

a) CTC allocation to Rate RS per prod allocator, Exhibit JMK-2:

Total CTC w GRT	$411,510,245
Rate RS Allocation	38.39%
Rate RS CTC	$157,967,079

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