PECO STATEMENT NO. 3-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

REBUTTAL TESTIMONY

OF

ALAN B. COHN

Responding to Opposing Party Testimony Regarding Regulatory Assets, Fossil and Nuclear Decommissioning, Jurisdictional Allocation and Other Accounting Issues

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I. INTRODUCTION

Q. Please state your name and business address.

A. Alan B. Cohn, 2301 Market Street, Philadelphia, PA 19103.

Q. Have you previously participated in this proceeding?

A. Yes. I submitted direct testimony (PECO St. No. 3) and various supporting exhibits (Exhibits ABC - 1 and ABC - 2) with PECO's April 1, 1997, filing. A statement of my qualifications is contained in my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony will address issues raised by the Office of Trial Staff ("OTS"), the Office of Consumer Advocate ("OCA"), the Philadelphia Area Industrial Energy Users Group ("PAIEUG"), the Environmentalists and the Department of the Navy with respect to the following matters:

<u>Regulatory Assets</u>

SFAS 109 - PAIEUG (L. Kollen); OCA (T. Catlin)

SFAS 106 - OCA (T. Catlin), Navy (R. Smith), PAIEUG (L. Kollen)

Pension Fund - Navy (R. Smith); PAIEUG (L. Kollen)

Present Valuing of Regulatory Assets - OTS (W. Weakly); PAIEUG (L. Kollen)

Design Basis Documentation - OTS (T. Weakly); PAIEUG (L. Kollen);
OCA (T. Catlin); Navy (R. Smith)

Peach Bottom/Limerick Water Chemistry - OTS (T. Weakly); PAIEUG (L. Kollen); OCA (T. Catlin); Navy (R. Smith)

Compensated Absences - Navy (R. Smith)

Deferred Fuel - OCA (T. Catlin); PAIEUG (L. Kollen)

Nuclear Decommissioning - OCA (T. Catlin); PAIEUG (L. Kollen); Navy (R. Smith); OTS (D. Gill)

Fossil Decommissioning - OCA (T. Catlin); PAIEUG (L. Kollen); Navy (R. Smith); OTS (D. Gill)

Depreciation Reserve Shift - Navy (R. Smith); Environmentalist (D. Schoengold)

Reserve Accounts - Navy (R. Smith)

PaPUC Audit - OCA (R. LaCapra)

Jurisdictional Allocator - OCA (L. Smith); Environmentalist (D. Shoengold)

II. SFAS 109

Q. Which parties' witnesses have expressed disagreement with PECO's claim for recovery of accumulated deferred income taxes recorded pursuant to Statement of Financial Accounting Standards No. 109 (SFAS 109")?

A. Mr. Catlin, on behalf of the OCA, and Mr. Kollen, on behalf of PAIEUG, have taken issue with the Company's claim. Mr. Catlin and Mr. Kollen do not dispute PECO's right to recover the SFAS 109 regulatory asset nor do they disagree with the amount that PECO has recorded as the generation-related portion of this asset. Rather, they contend that the accumulated deferred taxes recorded pursuant to SFAS 109 will be paid to the Federal and State governments over the average remaining lives of PECO's generating plants and, therefore, only the present value of that stream of future payments should be recoverable as a stranded cost (OCA St. 3, pp. 18-21; PAIEUG St. 3, pp. 11-18). As explained below, both Mr. Catlin and Mr. Kollen misunderstand the factors that drive the "reversal" of accumulated deferred taxes and, therefore, have assumed that such taxes will continue to be deferred for much longer periods than actually is the case. As a result, their present valuing proposal would provide customers with assumed tax benefits that do not exist, as PECO's witness, Mr. James I. Warren, explains in detail in his rebuttal testimony (PECO St. 9-R). Additionally, if adopted, the proposal offered by Messrs. Catlin and Kollen would require PECO to recognize a substantial write-off of its SFAS 109 regulatory asset, as explained by PECO's witnesses James W. Sharpe (PECO St. 23-R) and Benjamin A. McKnight III (PECO St. 19-R).

Q. What is the nature of PECO's claim for accumulated deferred income taxes recorded pursuant to SFAS 109?

A. In accordance with SFAS 109 and Statement of Financial Accounting Standards No. 71, Accounting For The Effects of Regulation (ASFAS 71"), PECO recorded a regulatory asset to reflect its right to recover deferred tax liabilities generated by the effects of tax/book timing differences that had been "flowed-through" to customers in the ratemaking process. These tax benefits are only temporary, i.e., PECO's tax liability was deferred, not eliminated. The tax reductive effect of these tax/book timing differences eventually "reverses," and the taxes that had previously been deferred become due and payable to the Federal and State governments. This effect is explained in detail in my direct testimony (PECO St. 3, pp. 34-39) and in Mr. Warren's direct (PECO St. 9, pp. 4-7) and rebuttal (PECO St. 9-R, pp. 2-4) testimony.

As also explained in my direct testimony, the SFAS 109 regulatory asset recorded by PECO derives from plant-related tax/book timing differences. As a consequence, the "reversal" of the associated deferred taxes is directly tied to the cash flows that fund the Company's recovery of its capital investment in such plant. This is explained in greater detail by Mr. Warren.

Under traditional rate regulation, a utility's capital investment in generating facilities would be recovered through depreciation accruals calculated on the basis of the useful lives of the physical assets. The depreciation accruals allowed in the utility's rates created the cash flows that funded recovery of the utility's capital investment. Therefore, the plant-related accumulated deferred taxes would "reverse" over a period that was tied to those cash flows.

The Electricity Generation Customer Choice and Competition Act (the "Competition Act") provides a mechanism for recovery of stranded costs that fundamentally changes the manner in which a utility will recover its capital investment in generating facilities. Specifically, the Competitive Transition Charge ("CTC") may be imposed for a period not to exceed nine years from the date of the Competition Act absent a Commission waiver. The CTC recovery does not occur before January 1, 1999, when the first stage of the phase-in to competition begins and, therefore, as PECO has proposed in its Restructuring Plan, the recovery period, absent Commission waiver, would be seven years (1999-2005). As a result, the cash flows that will fund the recovery of the Company's capital investment in stranded generating plant will be produced over the seven-year duration of the CTC rather than the remaining useful lives of the physical assets. Because cash flows and, therefore, income recognition are accelerated, so is the "reversal" of the plant-related deferred taxes. In short, the accumulated deferred taxes recorded pursuant to SFAS 109 will become due and payable over the same seven-year period the CTC is in effect.

Q. How did the Company recognize the pattern of deferred tax reversal in the presentation of its claim for recovery of the SFAS 109 regulatory asset?

A. The Company included in its stranded cost claim the generation-related portion of its SFAS 109 regulatory asset ($1,687 million) and proposes to recover this amount over seven years <u>without</u> a return. In short, the Company proposes to recover the SFAS 109 regulatory asset over the same period that the accumulated deferred taxes will be paid to the Federal and State governments. This is appropriate because the Company does not need the cash flow from customers until it makes the tax payments in each of the seven years beginning in 1999 and ending in 2005. Since there is a temporal match between PECO's recovery and payment, no time value benefit would accrue to PECO and, therefore, no present valuing of the regulatory asset is required.

Q. What arguments have Messrs. Catlin and Kollen advanced as the alleged basis for their present valuing proposal?

A. Both contend that present valuing over an approximately 25 year (Mr. Catlin) to 27 year (Mr. Kollen) period is necessary to reflect the manner in which the deferred taxes will be paid. For the reasons explained above and by Mr. Warren, that assumption is not correct. Additionally, both contend that their proposed present valuing approach reflects the manner in which the deferred taxes would have been recovered under "traditional regulation." Mr. Kollen suggests that the Competition Act requires that the Company not recover these taxes any sooner than they would have been recovered under "traditional regulation." The argument based upon this narrow interpretation and argument misconstrues what "traditional regulation" provided and misperceived the effects of the Competition Act on the Company's deferred tax liability.

As previously explained, under "traditional regulation" recovery of accumulated deferred income taxes was tied to the period established by the Commission for recovery of the Company's capital investment that generated the tax deferral benefits (e.g. the book life of the plant). Accordingly, changes in the book plant lives and accrual rates for ratemaking purposes would necessarily change the deferred tax recovery period as well. In its restructuring filing, the Company continued to adhere to this approach in presenting its SFAS 109 claim with appropriate recognition of the fact that the Competition Act itself has reduced the period for recovery of the capital investment in stranded generating plant to seven years. Mr. Kollen's contention that the Competition Act somehow requires that deferred taxes be recovered over approximately 27 years simply cannot be reconciled with the limitation, imposed by the Competition Act itself, that recovery of generating plant capital costs occur over seven years.

Stated another way, under "traditional regulation" a utility was permitted to recover its deferred tax liability from customers concurrently with its payment of such tax to the government. For this reason, "traditional regulation" did not create a time value benefit for the utility nor did it impose a time value penalty. PECO's claim for recovery of the SFAS 109 regulatory asset is entirely consistent with this principle. In contrast, under the proposal offered by Messrs. Catlin and Kollen, there would be a significant temporal mismatch, because PECO would actually pay deferred taxes to the government long before Messrs. Catlin and Kollen assume that the expenditures would occur. Consequently, the present value of PECO's expenditures for deferred taxes would exceed the present value of the portion of its SFAS 109 regulatory asset Messrs. Catlin and Kollen would allow PECO to recover. The difference would have to be written-off as a charge against income, as Mr. Sharpe and Mr. McKnight explain.

Q. Why is it appropriate to recover the SFAS 109 deferred tax balance as a regulatory asset?

A. The SFAS 109 regulatory asset represents the regulatory promise to permit the recovery of the tax benefits of tax/book timing differences that have previously been flowed through to customers. Because these tax benefits have, in their entirety, been provided to customers through reductions in prior period rates, it is proper to recover the SFAS 109 asset as a stranded regulatory asset.

Q. However, isn't a portion of the accumulated deferred taxes booked pursuant to SFAS 109 associated with the market value, i.e., the non-stranded portion, of the Company's generating plants?

A. Yes, it is. As a consequence, there is a portion of the deferred taxes booked pursuant to SFAS 109 that will reverse over the capital recovery period associated with the non-stranded portion of the Company's generating plant, namely, their remaining book depreciable lives. Therefore, the Company has added an appropriate credit to, i.e., increased, the market value of its generating plants to reflect that fact.

Q. How was that credit reflected in the market valuation calculations?

A. The market valuation model used by the Company starts with an after-tax cash flow value to which various adjustments are made, as detailed in Exhibits TPH - 3 to TPH - 5, to derive the market value of the plant. One of the components reflected as an addition to the present value of cash flow is accumulated deferred taxes. This addition consists of an allocated share of all generation plant-related deferred taxes, i.e., both from the accumulated deferred income tax reserve and deferred taxes recorded pursuant to SFAS 109. This computation effectively increases the market value of plant by an amount equal to the SFAS 109 deferred taxes allocated to the non-stranded portion of PECO's generating units.

Q. Mr. Kollen also contends that the Company has been inconsistent in its treatment of tax benefits, because it used a "net present value over the life of the assets theory" to distribute the tax-reductive effect of unamortized Investment Tax Credits ("ITC") and "future tax benefits" (PAIEUG St. 3, pp. 15-16). Has PECO been inconsistent?

A. No, not at all. I will begin with PECO's treatment of Investment Tax Credits ("ITC"). PECO has reflected the generation-related unamortized ITC as a ratable increase to after-tax generating plant income over the remaining lives of its generating facilities that gave rise to the ITCs. Total market income was discounted to present value at December 31, 1998, to determine the market value of PECO's generating assets. Consequently, Mr. Kollen is essentially correct that the net effect of this presentation is equivalent to reflecting unamortized ITCs on a net present value basis over the lives of its generating assets. However, the principal reason for reflecting ITCs in this fashion is to assure compliance with the normalization requirements applicable to ITCs. In fact, flowing ITCs back to customers more rapidly than over the lives of the assets to which they relate would create a substantial risk of violating the normalization requirements imposed by the Internal Revenue Code. Such a violation would trigger an immediate recapture of <u>all</u> ITCs, not just generation-related ITCs. Significantly, these normalization requirements were explained by Mr. Warren in his direct testimony in this proceeding (PECO St. 9, pp. 22-25) and in his rebuttal testimony in PECO's securitization case (PECO St. 11-R, pp. 13-14). However, Mr. Kollen does not even acknowledge that Mr. Warren presented this testimony.

Turning to the "future tax benefits" to which Mr. Kollen referred, it is essential to recognize that such "benefits" consist of future tax depreciation deductions related to PECO's generating plant. PECO did not reflect these deductions as occurring over seven years because applicable provisions of the Internal Revenue Code and Internal Revenue regulations do not permit these deductions to be taken over a time period that short. Tax depreciation deductions can be taken over the tax lives of assets as defined by the Code and regulations. To reflect those deductions as occurring over a shorter duration would give customers a hypothetical tax benefit that PECO itself does not obtain.

Q. Finally, Mr. Kollen also contends that PECO's method for recovering the SFAS 109 regulatory asset is inconsistent with the method employed by Pennsylvania Power & Light Company ("PP&L") and suggests that PP&L's approach is preferable. Is Mr. Kollen correct?

A. Mr. Kollen contends that PP&L "quantified its SFAS 109 regulatory asset at December 31, 1998 as the net present value of the future levels and patterns of SFAS 109 revenue recoveries under traditional regulation." Mr. Kollen's description grossly oversimplifies PP&L's methodology. Mr. Kollen's colleague, Mr. Falkenberg, explained that PP&L employed a fundamentally different approach to calculating the market value of its assets (PAIEUG St. 2, p. 11):

> PECO's method is more of a market oriented approach and computes the loss to shareholders based on the short fall between the after tax market value of their assets under

> competition compared to book value. The PP&L method attempts to compute the shareholder loss on the basis of the loss in pre-tax revenue under competition and regulation . . . The PECO method is intended to compensate shareholders for the reduction in value of their property. The PP&L method, on the other hand, seeks to establish and protect a perceived right of shareholders to future revenue streams associated with a static form of regulation.

Mr. Falkenberg concluded that "the PECO method is more appropriate for the purposes of this proceeding."

Q. How did PP&L calculate the market value of its generating assets?

A. PP&L calculated the annual revenue requirements under "traditional regulation" associated with its generating assets for each year of their remaining lives. PP&L also calculated the market revenue it estimated that these assets would produce each year over their remaining lives. The excess of revenue requirement over market value, reduced to present value at December 31, 1998, is PP&L's stranded cost claim. In calculating the revenue requirement associated with its generating assets, PP&L reflected recovery of the SFAS 109 regulatory asset using the pattern of recovery that would occur if these assets remained in a rate regulated environment for the balance of their useful lives. However, and as should be apparent from Mr. Falkenberg's critique, the same approach was used by PP&L for <u>all</u> other components of its revenue requirement. Mr. Kollen has selected a single element of PP&L's method for comparison to PECO and, on that basis, claims that PECO's approach is "inconsistent." In fact, Mr. Kollen is incorrect because he is looking at only one piece of the PP&L presentation and drawing incorrect conclusions.

Q. Please explain why you believe Mr. Kollen is looking at only one piece of the PP&L presentation.

A. Total revenue requirement associated with plant in service consists of four basic components: (1) return, (2) depreciation, (3) taxes and (4) the SFAS 109 regulatory asset. Fundamental present value theory dictates that the present value of the revenue requirement associated with plant is the same regardless of the lives used for book depreciation so long as the depreciable tax lives are constant. And, the tax lives are a constant because they are determined by the applicable provisions of the Internal Revenue Code.

Mr. Kollen has selected one component of plant-related revenue requirement (the SFAS 109 regulatory asset) for analysis and contends that if it is present-valued over a longer period of time its present value is lower. Clearly, that is correct. However, if all four components are compared in total, the total present value will be the same because the other components of plant-related revenue requirement (return, depreciation and taxes) will have increased.

Q. Can you provide an example illustrating this concept?

A. Yes. Exhibit ABC - 3 provides an example based upon $10,000 of plant investment, which compares the present value of revenue requirements assuming (1) a remaining life of seven years and (2) a remaining life of 20 years. The revenue requirement includes depreciation, pre-tax return, and SFAS 109 asset recovery. The present value of the revenue requirement for each component is summarized in the table below for each scenario:

	7 year (PECO)	20 year (PP&L)
Return (Pre-Tax)	$ 4,606	$8,954
Depreciation	7,236	4,627
SFAS 109	2,412	672
Total	$14,254	$14,254

As shown in this table, selecting only one component will distort the picture because, in total, the revenue requirements are equivalent. Selecting only the SFAS 109 component ignores the fact that other components also have changed.

Q. What does your example show about the comparison of the PECO and the PP&L methodologies for stranded cost?

A. First, the methodology used, whether PECO's or PP&L's, will result in approximately the same answer for stranded revenue requirements. This is because a consistent application of the PP&L method to all components of stranded revenue requirement would result in an increase in plant related stranded revenue requirement equal to the decrease in the SFAS 109 component.

Second, comparison of only one component of stranded cost can be misleading when fundamentally different methodologies were used in the first instance to calculate stranded cost.

Finally, the PECO method is preferable because it properly quantifies the SFAS 109 asset based on the actual capital recovery periods.

III. SFAS 106

Q. What adjustment has Mr. Catlin proposed with respect to the Company's claim for recovery of its SFAS 106 regulatory asset?

A. At the outset, it should be emphasized that Mr. Catlin agrees that the entire SFAS 106 regulatory asset claimed by the Company should be recovered. Mr. Catlin has proposed an adjustment to remove from the Company's claim $67.9 million which had been deferred and recorded as a regulatory asset in connection with the Company's implementation of its Voluntary Retirement Incentive Program and Voluntary Separation Incentive Program ("VRIP/VSIP"), as explained in my direct testimony (PECO Statement 3, pp. 31-34). Mr. Catlin does not take issue with PECO's deferral and recordation of a regulatory asset in this amount. However, he believes that the amortization of this portion of the SFAS 106 regulatory asset has already been reflected in the pension and benefits expense deducted from the estimated market revenue to be produced by the Company's generating plants in calculating their market value. Based on that assumption, Mr. Caitlin contends that to also permit PECO to recover the VRIP/VSIP portion of its SFAS 106 costs as a regulatory asset would be an improper "double count."

Q. Is Mr. Catlin correct that the VRIP/VSIP deferred costs have been included in operating expenses used to calculate the market value of PECO's generating units?

A. No, he is not. These costs have been excluded from the Company's operating plant market value calculations. The Company's workpapers for its market value calculations, which are provided in Exhibit ABC - 4, clearly show the exclusion. As shown on page 1 of Exhibit ABC - 4, the SFAS 106 regulatory asset amortization is deducted from A&G expense to obtain the amount used in the market value analysis (Exhibit ABC - 4, p. 2). Therefore, there is no double count and the VRIP/VSIP portion of the SFAS 106 regulatory asset is appropriately included in the Company's claim.

Q. What adjustments did Mr. Kollen propose with respect to the regulatory asset for SFAS 106 costs?

A. Mr. Kollen has proposed two adjustments, which would:

(1) eliminate the portion of the deferred costs related to the Company's VRIP/VSIP and

(2) credit against the Company's claim the earnings on the external trust created to fund its SFAS 106 liability (PAIEUG Statement 3, pp. 26-34).

Q. One of the reasons stated by Mr. Kollen for exclusion of the VRIP/VSIP regulatory asset is that the customers have not received the benefit. Is he correct?

A. No, as noted in my rebuttal testimony in PECO's Securitization proceeding, there are several flaws with this argument. First, the generation portion of labor cost savings of $100 million per year have already been recognized in the operating and maintenance expenses used to calculate the market value of the Company's generating assets. If Mr. Kollen wants to recognize those same savings as an offset to deferred SFAS 106 costs, he is making an obvious and erroneous double-count.

Second, he has ignored the fact that the Company, through its shareholders, incurred $250 million in costs associated with the VRIP/VSIP, which were booked in 1995 and have never been recognized in rates. These costs would offset virtually all of the VRIP/VSIP savings for the years 1995, 1996 and 1997.

Third, Mr. Kollen's whole approach to this issue is simply another form of impermissible line-item ratemaking. Although he is seizing the gross VRIP/VSIP savings, he is ignoring other cost areas for which increases occurred that are not reflected in the Company's rates.

Finally, this argument is based upon a misconception of what this regulatory asset really is and is not. SFAS 106 allows the amortization of the transition obligation over 20 years. Due to the VRIP/VSIP program, a portion of the transition obligation had to be recognized currently rather than over 20 years. The Company, however, had Commission approval to recover the cost over 20 years (Docket R-922479). It was, therefore, appropriate to establish the regulatory asset such that the book accounting followed the ratemaking. This balance is not an additional expense incurred due to the VRIP/VSIP.

Q. Have you previously provided Mr. Kollen the information, explained above, concerning the recognition of labor cost savings in the Company's market value calculation and the unreimbursed costs incurred to implement the VRIP/VSIP?

A. Yes, as I previously mentioned, this information was provided in my rebuttal testimony in PECO's securitization case (PECO Statement 2-R, pp. 9-11). However, the existence of that information has not been acknowledged by Mr. Kollen.

Q. Mr. Kollen also argues that the benefit of future post-retirement benefit fund earnings should be provided to customers. Is this appropriate?

A. No. Again, there is a misunderstanding as to how SFAS 106 expense is computed. SFAS 106 expense is effectively stated on a present value basis. There are four components to the SFAS 106 cost. They are the service cost, the transition obligation amortization, the interest component and a return on assets. The amortization of transition obligation is fixed. However, the service cost and interest expense components can grow rapidly. The fund earnings (return on plan assets) are necessary to help reduce the growth in the other components of expense. Without the benefit of the fund earnings the SFAS 106 expense would grow at a rapid rate. The earnings help control the expense level. What Mr. Kollen has done is to take the benefit of the earnings without reflecting the associated cost. Such an adjustment is totally inappropriate and would double count the benefit of the fund earnings.

Q. What adjustment has Mr. Smith proposed with respect to the Company's claim for the SFAS 106 regulatory asset?

A. Significantly, Mr. Smith has not proposed that any adjustment be made directly to the Company's claim for its SFAS 106 regulatory asset and, in fact, he does not dispute either the amount of the asset or PECO's right to recovery it in full. Rather, Mr. Smith contends that the amount by which the Company's pension trust is "overfunded" should be used to fully offset the SFAS 106 regulatory asset. The obvious flaw in this proposal is that the Company does not have access to the pension trust and cannot transfer funds between it and the separate trust established to fund its OPEB expense. Additionally, and as explained below, the Company has already provided the benefit of the pension fund surplus to customers in its stranded cost calculations.

IV. Pension Fund

Q. What adjustments have been proposed with respect to the Company pension fund?

A. The market value of the Company's pension fund assets currently exceeds its accumulated benefit obligation. As explained above, Mr. Smith proposes that the current excess be used to offset the Company's SFAS 106 regulatory asset.

Mr. Kollen proposes that pension excess be taken as a credit against the Company's stranded costs.

Q. Are such adjustments appropriate?

A. No, they are entirely inappropriate. At the outset, it should be emphasized that the apparent overfunding of the pension plan is a transitory situation. One or two years of lackluster performance of the stock market could reverse the overfunding situation. Additionally, because the Company does not have access to the pension funds, it is improper to credit the overfunding against stranded costs. The only benefit the Company could realize from the overfunding status is a lower annual pension expense, and the Company has already fully credited this lower expense level to the benefit of customers in its stranded cost calculation.

Q. How has the Company provided customers the benefit of the current pension fund excess?

A. Pension plan funding status directly affects the annual pension expense because the overfunded amount is amortized against, and reduces, the annual service cost. The generation-related service cost is approximately $13.4 million per year based on the latest actuarial study. Amortization of the pension fund excess provides a credit of $13.2 million against that cost, as shown in Exhibit ABC - 5. Accordingly, in calculating the market value of its generating plant assets, the Company included annual pension expense of less than $200,000. In this way, the Company has already given customers the full benefit of the pension plan overfunding by lowering the costs of generation and thereby increasing the market value of its generating assets. The adjustments proposed by Messrs. Kollen and Smith would double count this benefit.

V. Present Valuing of Regulatory Assets

Q. Several of the witnesses proposed discounting to present value regulatory assets on which the Company does not earn a return. For example, Mr. Kollen has proposed this treatment with respect to Limerick 1 and 2 declaratory order costs and other transition costs. (PAIEUG Statement 3, pp. 35-36 and 57-58) Is this appropriate?

A. It is an alternate method which mathematically should reach the same result if done properly. When regulatory assets that do not earn a return are discounted to present value, then the unamortized balance of such assets must earn a return during the CTC recovery period or a double discounting will occur. This is recognized by PAIEUG's witnesses, in as much as the regulatory assets Mr. Kollen discounts to present value are included in the balance on which Mr. Baron would allow a return over the CTC period (PAIEUG Exh. SJB - 2). Present valuing and allowing a return over the CTC period is the economic equivalent of the Company's treatment of these assets, namely, stating them at their nominal value and amortizing them over the CTC period <u>without a return</u> on the unamortized balance. The Company believes that its method is superior (i.e., more direct) because it avoids the need to do present value and return calculations and to select discount and returns rates for such calculations.

VI. Design Basis Documentation

Q. Messrs. Smith, Kollen and Catlin propose to disallow this cost because the Company did not seek prior PaPUC approval to defer the cost and because its recovery may constitute retroactive ratemaking. Is this claim retroactive ratemaking?

A. Absolutely not. This project was the result of concerns the NRC had expressed regarding the original design basis documents. The Company properly recorded the costs of the project in Account 183, Preliminary Survey and Investigation Charges, until the project was completed. Because the project would yield benefits over the life of the plant, but did not qualify as plant, the Company sought the FERC's approval to account for it as a regulatory study in Account 182, Unrecovered Plant and Regulatory Study Costs, and to amortize the cost over the life of the associated plant. The FERC approved this accounting treatment.

There are two other points to be made on the issue of retroactive ratemaking. First, the Company is not seeking recovery of amounts already amortized. Second, recovery of these costs will match the period over which the project's benefits will be realized. The real issues are whether the project is prudent and whether it will provide benefits to customers. The answer to both is yes. The appropriate accounting and ratemaking flows from those facts.

Q. Was PaPUC approval necessary to record the costs in the manner PECO did?

A. No. Pennsylvania follows FERC accounting, and these costs were recorded in accordance with FERC requirements. The issue is not one of deferral, but rather whether appropriate accounting procedures were employed. FERC agreed that recording the cost in Account 182 and amortizing it over the life of the plant was proper. Additionally, I would note the Commission's Bureau of Audits reviewed the Company's regulatory assets and deferred charges and proposed no adjustments.

VII. Peach Bottom and Limerick Water Chemistry

Q. Messrs. Catlin, Smith and Kollen oppose PECO's claim for the costs of the Peach Bottom and Limerick Water Chemistry System changes for the same reasons they oppose the design basis documentation claim. Please address their arguments.

A. There are additional distinguishing factors with respect to this claim. These projects started as CWIP and, upon completion, were to be included in plant in service. Because the projects were not fully operational prior to 1997, the Company sought FERC approval to record the cost in Account 182 rather than plant in service. However, the water chemistry systems are now operational in at least one unit at both Peach Bottom and Limerick and, therefore, will be recorded as plant in service. As such, these costs would properly also earn a return. The Company has not modified its claim to request a return on these plant assets.

Q. Mr. Smith asserts that even if this project is operational, the delay in completion probably increased its cost. Is this correct?

A. No. Mr. Smith's assertion has no basis. During the suspensions of the project, the Company did not accrue AFUDC. Absent the accrual of AFUDC, there are no other expenditures that would be incurred during a suspension or project cancellation, and therefore, costs would not be higher due to the delay.

VIII. Compensated Absences

Q. Mr. Smith contends that this item is not appropriately categorized as a regulatory asset. Do you agree with that assertion?

A. No. Mr. Smith misunderstands how the Company accounts for compensated absences. Currently, these costs are recoverable on a pay-as-you-go basis. The regulatory asset recorded on the books represents the amount that has been accrued to date for generation-related employees. Recordation of a regulatory assets is proper because, under traditional ratemaking, that asset would be recovered in the future as the pay-as-you-go amounts were recovered in rates. Because the existing balance is associated with prior service, it is appropriately recovered as a stranded or transition cost. If not included as a regulatory asset, the pay-as-you-go expense would have to be included in the market value analysis where it would increase operating and maintenance expense and, as a result, decrease the market value of PECO's generating plants, thereby increase stranded generating plant costs.

IX. Deferred Fuel

Q. Messrs. Catlin, Kollen and Smith oppose PECO's recovery of its estimated deferred fuel costs for 1997-2005 because they contend the claim is speculative and not known and measurable. Please address this contention?

A. "Known and measurable" in the context of projections must be based upon the reasonableness of the projection. The amount claimed by the Company is based upon a projection derived from a 4-year historic average. A check on the reasonableness of this projection can be established by preparing a deferred fuel calculation for the period from January to May to determine how it tracks the estimated $22 million annual deferral claimed by PECO. Exhibit ABC - 6 provides such a calculation. As shown, the year-to-date deferral is $19.7 million, after adjusting for Salem replacement power. Given that this reflects only five months of deferral, it appears that the Company's estimate of $22 million per year is quite conservative.

Q. Please address Mr. Catlin's contention that because the Energy Cost Adjustment ("ECA") was eliminated there should be no deferral?

A. Such a position is contrary to the Commission's Order of May 22, 1997, which stated the following:

> That (a) PECO Energy Company shall have the right to defer, and, in the future, to seek full recovery of an amount that represents the difference between the rolled-in rates and a figure that reflects PECO Energy Company's average fuel costs, which difference is to be determined in conjunction with PECO Energy Company's restructuring filing submitted on April 1, 1997; . . .

X. Nuclear Decommissioning

Q. Messrs. Catlin and Kollen note that earnings have not been calculated on the 1997 and 1998 fund contribution. Is this correct?

A. Yes. The Company inadvertently excluded such earnings and is revising its claim to reflect the change. The estimated impact is to reduce the claim for nuclear decommissioning stranded costs from $236.9 million to $233.8 million.

Q. Messrs. Catlin and Kollen propose the use of the annuity method of calculating the decommissioning expense. Do you believe the use of this method is appropriate?

A. No. The Commission has historically used the constant current accrual method for PECO in calculating decommissioning expense. Furthermore, the annuity method would inequitably assign the entire risk of future decommissioning cost to shareholders because that method is dependent not only upon cost estimates, but cost escalation and earnings rate assumptions as well. The Company's methodology provides a reasonable balancing by allocating costs based upon each plant's years in operation. The underfunded portion of the proportional cost of decommissioning for the pre-1999 period is recovered during the transition period. As to the future portion, the Company does in fact use the annuity method, because it is consistent with the methodology used to develop market value.

Q. Would the Company agree to the annuity method if there was a separate decommissioning rider or charge to periodically reflect changes in decommissioning costs?

A. Yes, if this mechanism (1) was permitted to reflect decommissioning cost changes, (2) the Commission otherwise determined that the annuity method is acceptable and (3) recovery was made part of the distribution business, the Company would have no objection.

Q. Messrs. Gill and Kollen state that the Commission should assume that decommissioning expense in the post-1998 period is tax deductible. Do you agree that such an assumption is appropriate? 4484 240

A. No. It is clear that absent a special charge for recovery of decommissioning expense the recovery of that cost is not subject to cost-of-service regulation in the post-1998 period. If the expense is not cost-of-service regulated, then it is <u>not</u> tax deductible as a matter of law. To nonetheless impute a tax deduction would base PECO's cost recovery on an assumption that is contrary to reality and, thereby, significantly understate PECO's costs. However, as explained in detail in my direct testimony (PECO Statement 3, p. 16), if the Commission were to establish a separate charge for decommissioning expense, IRS criteria for deductibility could be satisfied.

Q. Mr. Gill proposes to reduce the going-forward decommissioning expense from \$36.7 million to \$22.7 million to reflect tax deductibility. Do you concur with this adjustment?

A. No. For the reasons stated previously it is not appropriate to assume tax deductibility after 1998. I should note that the Company has revised the going-forward cost to $32.1 million in a revised response to PAIEUG - VIII - 19. The relevant schedule from that response is provided as Exhibit ABC - 7.

Q. The issue of mitigation with regard to nuclear decommissioning has been raised by Mr. Biewald and Mr. Metro. Has the Company made substantial efforts to mitigate the cost of decommissioning?

A. Yes, this mitigation should be looked at in total, not based upon specific components. With that in mind, the Company has mitigated the cost of decommissioning in two important ways. First, the cost studies completed by Mr. LaGuardia included a 25% contingency factor in developing the final cost estimates. The Company, however, used only a 10% factor. This reduced the total cost by about $145 million in 1995 dollars. Second, the Company used the annuity method for the post-1998 period. A key assumption in this methodology is the escalation rate for decommissioning costs. The Company has used the GDP implicit price deflator, which established a future escalation rate substantially lower than historic rates of escalation. As should be evident, the Company's claim already reflects substantial mitigation. To impute additional, unrealistic levels of mitigation would not give the Company a reasonable opportunity to recover its costs.

XI. Fossil Decommissioning

Q. Mr. Catlin proposes the use of the annuity method for recovery of fossil decommissioning cost. Do you agree with this proposal?

A. No, I do not. The recovery of the portion of such costs associated with the pre-1999 period should be determined based upon the Company's methodology. Use of the annuity method would require additional assumptions about cost escalation and earnings rate and would increase the risk of the Company not recovering its full cost. Regarding the future (post-1998) period, the Company would not oppose using the annuity methodology, although it continues to believe that its method is preferable for this period as well because it is less sensitive to assumptions about the future costs.

Q. Mr. Kollen contends that recovery of fossil decommissioning as a part of PECO's stranded cost claim may be barred by the <u>Penn-Sheraton</u> decision, and he references your direct testimony in this regard. Do you wish to comment?

A. Yes. The point of my direct testimony was that, while fossil decommissioning costs are real and substantial, utilities did not historically recover these costs over the life of their generating units because <u>Penn Sheraton</u> had been read to bar prospective recovery of negative net salvage, which would include decommissioning. As a consequence; decommissioning costs are now recoverable as "stranded costs as recognized by Section 2803," which defines "transition or stranded costs" to include:

> (3) the following costs, the recoverability of which shall be determined pursuant to Section 2808 (c)(3): . . .
>
> > (iv) retirement costs attributable to the utility's existing generating plants other than the costs defined in Paragraph (1) [projected nuclear plant decommissioning costs].

I would note that if Mr. Kollen believes that the Commission cannot legally allow recovery of these costs, the appropriate solution would be to include the cost in the market value study in the years the Company expects to incur them.

Q. Messr. Kollen and Gill note that life extensions were not considered in determining the fossil decommissioning cost. Is that correct and, if so, why is it appropriate?

A. Messrs. Kollen and Gill are correct that the Company has not reflected life extensions in calculating fossil decommissioning expenses. The life extensions were included in the market value study because they provide a net market value benefit under current assumptions and inputs to the market value study. Accordingly, assuming life extensions reduces net stranded costs. However, no official decisions have been made regarding the life extensions because, obviously, a number of factors affecting such decisions could change over the intervening years. It would, therefore, be inappropriate to include such extensions in determining decommissioning expense. Using the longer life could result in an underrecovery of decommissioning cost, whereas, the shorter life will not result in an overrecovery.

XII. Depreciation Reserve Shift

Q. Messrs. Smith and Schoengold address the issue of the proposed depreciation reserve shift. Please summarize their respective positions.

A. Mr. Smith describes the reserve shift as transferring the burden of uneconomic generation costs to transmission and distribution customers as compared to leaving such costs with the customers that caused them to be incurred. For that reason, he opposes the reserve shift. Mr. Shoengold believes that a depreciation shift would transfer cost burdens from industrial and wholesale customers to residential and commercial customers. Although he did not make a specific recommendation, he encouraged the Commission to carefully review the life study that would be used as one basis for the reserve shift, if they were to consider adopting PECO's proposal.

Q. Please respond to Mr. Smith's position?

A. Mr. Smith assumes that the Company is shifting an arbitrarily-determined reserve amount from distribution to generation. However, that is not the case. The Company's reserve shift is supported by theoretical reserve calculations based upon a new service life study and, therefore, is fully consistent with cost causation principles.

Q. Please respond to Mr. Schoengold's position?

A. The Company agrees that the Commission should carefully review the basis for the proposed reserve shift. In that regard, I would note that the Company has filed the relevant service life study. As to the cost shifting argument, the Company does not agree with Mr. Shoengold. The reserve shift affects the costs that are included in the generation and distribution functions. However, once the costs are functionalized, allocations among the classes are made on the basis of the allocation method used to establish existing rates. As the Competition Act recognizes, the consistent use of the proven allocation method avoids any improper inter-class cost shifting.

Q. Has Mr. Hill requested that you quantify the potential reserve shift, including the impact from transmission plant?

A. Yes.

Q. What are the results of your analysis?

A. As noted in my direct testimony (p. 51), the impact of the distribution plant reserve shift is $175,661,000. The estimated impact of the reserve shift on transmission plant is an additional $94,825,000 above the distribution plant component. This estimate can be derived from Exhibit ABC-1, Schedule 9. The total impact of the reserve shift therefore becomes $270,486,000.

XIII. RESERVES ACCOUNTS

Q. Do you agree with Navy witness Smith's recommendation that generation related reserve accounts for property damage and personal injury and workers' compensation should be offset against stranded cost?

A. No, this is clearly inappropriate. The property damage and personal injury reserve account was established after PECO's last rate case (Docket No. R-891364). Thus, only shareholder monies, not customer provided funds, were used to establish these reserves, as explained in my response to Interrogatory PAIEUG-V-9. Mr. Smith suggests that, therefore, the expenses being reserved for are "shareholder" expenses and these categories of expenses should be removed from the Company's market value calculations of its generating plants. That is not the case.

First, Mr. Smith misinterprets shareholder funding. Typically when changing to reserve accounting, there is a doubling-up of the expense in the year the reserve is created. The point I made was that because the reserve was established subsequent to the Company's last rate case, shareholder dollars must have funded the reserves.

Second, property damage and personal injury claims are generally related to the distribution function, as evident by the most common claims, which are for damages from power surges or outages. For that reason, this expense has not been included in the determination of the stranded cost of PECO's generating plant assets and, therefore, Mr. Smith's argument simply does not apply.

Regarding the workmen's compensation claim, these dollars will be paid out as claims are made. Therefore, to offset this reserve against stranded costs would give customers credit for amounts that the Company will ultimately be paying out in claims. Because it is basically a timing difference on payment, it is already reflected in the cash working capital element of the Company's market value calculation.

Therefore, if Mr. Smith's adjustment were adopted, the customers would receive the same benefit twice.

XIV. PaPUC Audit Adjustment

Q. Mr. LaCapra proposes to reduce net plant by $35,214,000 to reflect the results of the Commission is property records audit. Is such an adjustment appropriate?

A. No, it is not. The PaPUC audit noted that there was $35,214,000 in generation plant that should have been retired. The specific adjustment proposed in the audit reduced both plant-in-service and accrued depreciation by $35,214,000. The net result is no change in net plant, i.e. the depreciated original cost of plant-in-service would remain the same. Accordingly, Mr. LaCapra's proposed adjustment is erroneous and inconsistent with the audit's findings. No change in net plant is required as a result of the audit.

XV. JURISDICTIONAL ALLOCATOR

Q. Will you please briefly describe the jurisdictional allocation adjustments proposed by OCA witness Lee Smith and Environmentalist's witness David Schoengold?

A. Yes. First, OCA witness Smith proposed to reduce the Company's jurisdictional allocator by 4.05%. The purported basis for the proposed adjustment is to allocate a portion of the cost responsibility for generating plant to firm wholesale customers.

Ms. Smith assumes that the sales PECO makes to Delmarva Power & Light Company to serve the load of the customers of the former Conowingo Power Company ("COPCo") are firm sales, because COPCo was formerly a PECO affiliate which the Company sold to Delmarva. To calculate her proposed adjustment, Ms. Smith used the relationship between the demand associated with sales to COPCO (calculated using the Company's 4CP method) and the energy sales to COPCO as determined in PECO's last Pennsylvania base rate case. As a result, Ms. Smith implicitly assumes that this "4cp/kWh" ratio is the same as the ratio of the 4CP demand and the current level of sales to Delmarva which, as explained below, is not the case. To obtain the nonjurisdictional allocator, Ms. Smith multiplied this ratio by the % of total sales represented by sales to Delmarva reported in Mr. Clemmer's cost allocation study.

Mr. Schoengold allocates a portion of stranded cost to nonjurisdictional sales based upon firm wholesale capacity. He then present values and levelizes the retail share of capacity. The retail share is defined as

$$\frac{\text{Retail Peak Load}}{\text{Retail Peak Load \& Firm Wholesale Load}}$$

This yields a 5.5% allocation to nonjurisdictional sales.

Q. Please explain, in general, the problems with each witness' approach to calculating the jurisdictional allocation of stranded cost.

A. First, retail sales have priority over wholesale sales given the Company's obligation to serve, which will continue as long as the Company charges a CTC. Therefore, the most reasonable method, consistent with prior Commission precedent, to determine the jurisdictional allocation is the one Mr. Cucchi describes in his direct testimony (PECO Statement No. 15), which takes into account reasonable capacity planning considerations. Specifically, retail load is projected and required reserve margin is added. That figure is then compared to installed capacity. If all installed capacity is required to serve retail load with an adequate reserve margin, then the installed capacity is properly allocated to Pennsylvania jurisdictional service. To the extent the Company has firm wholesale commitments, then the additional capacity to serve firm wholesale customers must be purchased.

Q. Please discuss your concerns with Ms. Smith's proposal.

A. As previously mentioned, Ms. Smith assumes a constant relationship between sales and the 4CP demand for the COPCo load. That is not the case. The proper way to describe this relationship would be to express the COPCo peak as a percent of total peak load. In fact, that is what Mr. Schoengold did as the first step in his analysis. Correcting the error would reduce Ms. Smith's adjustment to about 3.0%. In Exhibit ABC-8 I have provided a spreadsheet showing these calculations.

Q. Please discuss your concerns with Mr. Schoengold's proposal.

A. As previously explained, Mr. Schoengold discounts the jurisdictional allocation and levelizes it. The discounting is inappropriate, because it effectively penalizes the

Company for the reality of reasonable capacity planning. It is generally accepted that there is a "lumpiness" to new capacity additions. When new capacity is first brought on line, there will be somewhat more than is required to meet immediate peak loads plus reserve requirements. Because discounting ignores this effect, Mr. Schoengold's analysis effectively *penalizes* the Company for the reality of how capacity additions are made..

A second problem with Mr. Shoengold's analysis is that his discounting begins in 1997 instead of 1999, when competition starts. Even using his discounting methodology but employing a start date of 1999 reduces the proposed allocation to nonjurisdictional sales to 3.8%. In Exhibit ABC-9 I have provided a spreadsheet showing these revised calculations.

Finally, Mr. Schoengold also assumes that the retail allocation must be 100% or less. This too has the effect of penalizing PECO for reasonable planning, because there could be extra capacity early on, when a new unit is first added, and a corresponding deficiency before the next unit is brought on line. That pattern justifies recovery, in the early years, of the entire costs of the newly added extra capacity. Allowing the jurisdictional allocator to rise above 100% recognizes the potential for offsetting capacity deficiencies prior to the addition of new units.

XVI. ADJUSTMENTS TO GENERATION ASSETS

Q. Several parties to the proceeding have recommended that a portion of general and common plant be allocated to generation. Has the Company revised its generation assets to reflect this recommendation?

A. Yes. Mr. Clemmer discusses the allocation of common and general plant in his rebuttal testimony. I have used Mr. Clemmer's analysis to determine the percent of total common and general plant allocated to generation. The calculated percentages were then applied to the estimated December 31, 1998 balance to determine the amount to be added to potentially stranded generation assets. Exhibit ABC - 10 shows the derivation of the additional $98.9 million for common and general plant. I have also provided a revised Exhibit ABC - 1, Schedule 1, to reflect this change as well as the decommissioning cost change discussed earlier in my rebuttal testimony.

Q. Does this conclude your testimony?

A. Yes.

R-00973953

PECO STATEMENT NO. 3-RJ

Phila 10/14, 10/15, 10/16/97
E. Holbert

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

REJOINDER TESTIMONY
OF
ALAN B. COHN

**Responding To PECC Witness Steven A. Mitnick
Concerning PECO's Recovery Of Stranded Costs
Under The Proposed Partial Settlement**

October 8, 1997

REJOINDER TESTIMONY OF ALAN B. COHN

Q. **Please state your full name and business address?**

A. My name is Alan B. Cohn. My business address is 2301 Market Street, Philadelphia, PA 19103.

Q. **Have you previously submitted testimony in this proceeding?**

A. Yes. I submitted direct testimony (PECO Statement No. 3) and various supporting exhibits (Exh. ABC-1 and ABC-2) with PECO's April 1, 1997 filing. I also submitted rebuttal testimony (PECO St. No. 3-R) and accompanying exhibits (Exh. ABC-3 through ABC-10) on July 18, 1997. A statement of my qualifications is contained in my direct testimony.

Q. **What is the purpose of your rejoinder testimony?**

A. The purpose of my rejoinder testimony is two-fold. First, I will identify the numerous fundamental errors in Mr. Mitnick's calculations of how much PECO would recover under the Partial Settlement. Second, I will provide the Company's estimate of the value of the Partial Settlement which, unlike Mr. Mitnick's flawed analysis, takes into account all elements of the Partial Settlement. My analysis clearly shows that the Partial Settlement will not result in PECO recovering more than the value of stranded costs stated in the Joint Petition.

Errors In Mr. Mitnick's Calculations

Q. Please summarize the errors in Mr. Mitnick's calculations that you will address.

A. As I will explain below, there are six fundamental errors in Mr. Mitnick's calculations, which result in his vastly overstating the value of the Partial Settlement to PECO:

(1) Mr. Mitnick tries to measure the value of the Partial Settlement to PECO by erroneously comparing the present value of the CTC revenue stream to the book value of PECO's stranded costs. The CTC revenue stream must be compared to the revenue requirement imposed by the recoverable stranded costs over the recovery period.

(2) He erroneously ascribes tax benefits to a book write-off, which does not produce a tax deduction.

(3) He miscalculates the effect of securitization and totally misconstrues the effect of tax deductibility of Transition Bond interest payments.

(4) He uses an outdated sales forecast that cannot be supported by objective evidence of PECO's sales levels.

(5) He errs in calculating the present value of the CTC revenue stream because he improperly discounts the revenue stream to January 1, 1999, rather than September 1, 1998, when the Partial Settlement will become effective and rate reductions will begin.

(6) He fails to take into account all elements of the Partial Settlement, which include elements that offset the value of CTC recovery.

Q. Please address Mr. Mitnick's error in comparing the present value of the CTC revenue stream to the book value of stranded costs.

A. The stranded costs recoverable under the Partial Settlement consist largely of assets upon which PECO is entitled to earn a return. Under the Partial Settlement, these costs will be recovered over a 10-year period and, therefore, the revenue requirement imposed by the stranded cost recovery includes the pre-tax return on the unrecovered balance. The present value of this revenue requirement is greater than the book value of the stranded costs to which it relates. Accordingly, the only proper measure of the value of the Partial Settlement is a comparison of the present value of the CTC revenue stream to the present value of the revenue requirement associated with the 10-year recovery of stranded costs. Mr. Mitnick's error of comparing revenue to book value produces $600 million of the alleged "overrecovery" in his calculations.

Q. Mr. Mitnick also contends that there is a "tax benefit" associated with PECO's proposed $2.0 billion write-off and that the alleged "tax benefit" is a source of cash flow that could be used to "mitigate" PECO's stranded costs. Do you agree with Mr. Mitnick's contention?

A. Absolutely not. As explained in the Rejoinder Testimony of James I. Warren (PECO St. 9-RJ), PECO's agreement to forego recovery of $2.0 billion of regulatory assets does not, and could not, generate a tax deduction. Mr. Warren also demonstrated that there is no tax benefit generated. Consequently, there is no cash benefit to PECO.

Additionally, even if one were to assume -- contrary to law -- that a current tax benefit might be produced, the tax effect should remain with shareholders because they would absorb the costs that would generate any deduction. This has always been the case under regulation. For example, if a utility's expense claim is disallowed, the tax effect of the utility's payment of the expense is <u>not</u> passed through to customers in the ratemaking process. Similarly, if a capital asset is excluded from rate base, the tax depreciation deductions associated with the asset are likewise excluded in setting rates. Simply stated, the tax effect should not be separated and allocated to customers while the cost is assigned to shareholders. The illogical consequences that flow from Mr. Mitnick's position are best illustrated in the example where PECO would forego recovery of all stranded costs. Under Mr. Mitnick's view, the Company, in that event, would <u>owe</u> customers approximately $3 billion, i.e., total stranded costs multiplied by the composite tax rate.

Q. **Regarding securitization, Mr. Mitnick assumed a 1% rate reduction for each $1 billion of assets securitized. Do you agree with this estimate?**

A. Not for the purposes of specific calculations applicable to PECO, other than it was a "rough" rule of thumb used to estimate securitizations impacts absent specific data. Mr. Mitnick has not provided any support for that estimate. In fact, the Company's securitization filing showed a 2.9% rate decrease for $3.6 billion of assets securitized, or approximately 0.8% per $1.0 billion. However, even that figure overstates the benefits of securitization in the context of the Partial Settlement because it does not take into account the proposed \$2.0 billion write-off. The write-off will result in a substantial decline in the Company's equity ratio. Therefore, in order to maintain its current capitalization ratios, the Company would have to use the first \$1.2 billion of securitization to retire currently outstanding debt. Using Transition Bonds to retire debt has a far smaller benefit than using the proceeds of the Bonds to displace equity capital. Therefore, even in Mr. Mitnick's scenario, the maximum benefit would be only 2.8%, even if all \$4.0 billion could be securitized ([\$4.0 billion - \$1.2 billion with no value] x 1% per billion).

Q. **Mr. Mitnick also states that there are "tax savings" produced by the deductibility of interest on securitization bonds, which should be used to mitigate stranded costs. Do you agree?**

A. Absolutely not. While he is correct that the interest is deductible for tax purposes, he leaves out a very important point. The revenue PECO would receive to pay the interest is fully taxable. As such, there is no net tax benefit from the deductibility of the interest. For example, if one were to collect \$10 in revenue to pay \$10 in interest cost, the tax liability is the same as if one collected no revenue and incurred no interest expense, i.e., \$0. Moreover, because one's interest payment obligation is \$10, \$10 in revenue must be collected in order to have sufficient funds to pay that obligation.

Q. **What is the impact of Mr. Mitnick's erroneous adjustment for alleged tax "savings" associated with the interest on securitization bonds?**

A. This one error alone results in Mr. Mitnick overstating PECO's recovery by $500 million.

Q. Mr. Mitnick proposes using the sales estimate implicit in the Company's 1997 Annual Resource Planning Report ("ARPR") to quantify CTC recovery under the Partial Settlement. Do you agree with the use of those data?

A. No. First, I would note that the ARPR forecast he relied upon is from the 1996 ARPR. This forecast was developed in 1995 and is over two years old. The Company is currently in the process of developing a new sales forecast, which I expect will be markedly different as a result of changes in sales levels since 1995.

Second, I have reviewed a history of retail sales for the 10-year period from January 1, 1988 to August 31, 1997. As shown in Exhibit ABC-11, sales have been flat over this period of time. This is in spite of a strong economy and a decline in the real price of electricity. In fact, actual sales for the 12 months ended August 1997 are approximately equal to the 10-year average. Even so, I have used the proforma 1996 sales level (33,569 MMWH), which is about 2% higher than actual 1996 sales, as a reasonable projection. Use of the ARPR sales projection, as Mr. Mitnick proposes, would overstate PECO's likely revenue recovery by about $400 million.

Q. Did Mr. Mitnick err in calculating the present value of the CTC revenue stream?

A. Yes, he discounted the revenue stream to January 1, 1999, rather than September 1, 1998, which is the date when rate reductions under the Partial Settlement would begin. As a result, Mr. Mitnick has overstated the present value of the CTC revenue recovery by $175 million.

Q. **You previously noted that Mr. Mitnick has failed to take into account components of the Partial Settlement which impose additional costs on PECO. Please explain.**

A. Mr. Mitnick has not taken into account the Partial Settlement's provisions that require PECO to put in place a 10% discount four months earlier than the start of electric competition, expand its Customer Assistance Program, extend the cap on transmission and distribution rates ("T&D rate cap") and eliminate certain EER and LILR-related charges. These obligations significantly reduce the value to PECO of the CTC revenue recovery provided for under the Partial Settlement.

Q. **What is the impact of the early rate reduction being offered as part of the Partial Settlement?**

A. The early rate reduction reduces PECO's revenue by approximately $110 million during the period from September 1 to December 31, 1998. By excluding this from his analysis, Mr. Mitnick overstates PECO's recovery by the same amount.

Q. **Mr. Mitnick states that it is unlikely that the transmission and distribution ("T&D") charges will increase above 2.63¢/kWh over the next ten years. Do you agree?**

A. No. First, the 2.63¢/kWh figure, which is Mr. Reising's estimate, is incorrect. The proper level for T&D costs is 3.11¢/kWh, as noted in Schedule A of the Partial Settlement and supported in Mr. Clemmer's rebuttal and rejoinder testimony. Second, a comparison of the T&D costs included in the Company's initial pilot filing in February 1997 with the current restructuring estimate will provide a guide for expected growth in T&D costs. As shown in Exhibit ABC-12, the T&D cost in the February 1997 filing was 2.60¢/kWh based upon a 1990 test year. This compares to the 3.11¢/kWh in the restructuring filing based upon a 1996 test year. This is an increase of 20% during a period when PECO was significantly reducing costs. It is reasonable to expect continued growth will occur at such a rate, at a minimum, because capital expenditures for replacement of facilities and improvement of reliability exceed depreciation.

PECO's Estimate Of Recovery Under The Partial Settlement

Q. **Have you performed an analysis of the amount of stranded costs PECO would be provided the opportunity to recover under the Partial Settlement?**

A. Yes. My analysis shows that the Company will recover approximately $6.02 billion in present value revenues, which is virtually the same as the revenue requirement associated with the $5.461 billion in stranded costs mentioned in the Joint Petition. However, as I explain later, PECO's ability to recover as much as $6.02 billion is contingent upon its securitizing a substantial portion of its recoverable stranded costs and experiencing some sales growth.

Q. **Why is the present value of the revenue recovery greater than the book value of the recoverable stranded costs?**

A. As I explained previously, a proper comparison must relate revenues to the revenue requirement of stranded costs, not revenues to the $5.461 billion book value of stranded costs. The revenue requirement associated with a 10-year recovery of $5.461 billion in stranded costs is approximately $6.02 billion. The primary reason that it is higher is that revenue requirement includes a return on investment (i.e., the unamortized balance of stranded costs) at a pre-tax level (i.e., what has to be collected to recover return and associated income taxes). However, for present value analysis, an after-tax cost of capital is used for discounting. Consequently, there would be no overcollection by PECO under the Partial Settlement.

Q. **Please describe the analysis you have performed.**

A. As shown in Exhibit ABC-13, in order to determine the nominal revenue recovery under the CTC, I multiplied annual sales by the CTC for each year of the recovery period. I used proforma 1996 sales as a reasonable estimate of annual sales levels for that period. The revenue was then reduced by 4.4% for the gross receipts tax and discounted to present value at September 1, 1998. Next, the impact of the four-month rate reduction beginning September 1, 1998 was calculated. This was then deducted from the present value of the CTC revenue to get a recovered amount prior to other elements of the Partial Settlement. As shown, this results in present value revenue recovery of $5.787 billion, or approximately $0.237 billion less than the revenue requirement of the stranded costs recoverable under the Partial Settlement.

I then evaluated the other elements including: (1) expansion of the CAP rate for universal service; (2) elimination of certain EER and LILR-related charges; (3) the cost of the additional two and one-half years of the T&D rate cap; (4) potential sales growth; and (5) the potential securitization benefits. As I previously explained, expansion of the CAP rate, elimination of EER and LILR-related charges and extension of the T&D rate cap impose substantial additional costs and, therefore, increase the level of underrecovery. The aspects of the Partial Settlement that might provide an opportunity to make up the total shortfall are the potential securitization benefits and growth in sales, if any. As shown in Exhibit ABC-13, the Company has to obtain $237 million in value from the net effect of all other factors to augment the CTC revenue recovery. At this level, the total value of the Partial Settlement is approximately $6.02 billion, or approximately equal to the stranded cost revenue requirement. In order to achieve such value, PECO will have to be able to securitize a substantial amount of stranded cost and achieve some sales growth.

Q. **In summary, Mr. Cohn, based upon your analysis, is the Company likely to overrecover the level of stranded costs stated in the Partial Settlement?**

A. No. My analysis shows that, given reasonable assumptions, there would be no overcollection and a potential for underrecovery, which is a risk borne by the Company under the terms of the Partial Settlement.

Q. **Mr. Cohn, does this conclude your rejoinder statement?**

A. Yes, it does.

PECO STATEMENT NO. 12-RJ

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

**APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE**

REJOINDER TESTIMONY

OF

ROBERT A. CLEMMER

Regarding Cost Allocation

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REJOINDER TESTIMONY OF ROBERT A. CLEMMER

I. INTRODUCTION

Q. Please state your full name and business address.

A. Robert A. Clemmer, 2301 Market Street, Philadelphia, PA 19101.

Q. Mr. Clemmer, have you previously presented written direct and rebuttal testimony in this proceeding?

A. Yes. I previously submitted PECO Statement Nos. 12 and 12-R and accompanying Exhibits RAC-1 through RAC-11.

Q. Mr. Clemmer, what is the purpose of your rejoinder testimony?

A. The purpose of my rejoinder testimony is to respond to certain claims made by Messrs. Reising and Mitnick on behalf of the Pennsylvania Electric Competition Coalition, which is comprised of Enron, Conectiv, and New Energy Ventures ("Enron" or "PECC"), and Mr. Johnstone on behalf of the Mid-Atlantic Power Supply Association ("MAPSA") in opposition to the Partial Settlement. In particular, I will respond to the following contentions:

- PECO assigned or allocated too much A&G and common plant (including intangible plant) costs to the transmission and distribution functions;
- PECO allocated too much uncollectible accounts, customer accounts, and sales expense to the transmission and distribution functions;

- PECO's assignments of A&G, common plant, sales, and customer-related costs will result in cross-subsidization; and
- PECO's proposed rate design is inconsistent with its cost allocation.

I will explain why every one of these contentions is without merit.

II. ADMINISTRATIVE AND GENERAL (A&G) AND COMMON PLANT ASSIGNMENTS

Q. What is the principal criticism of Messrs. Reising, Mitnick and Johnstone with regard to your assignments and allocations of A&G and common plant costs?

A. They renew the claim that PECO improperly allocated generation-related A&G and common plant costs to the transmission or distribution functions.

Q. Has either Mr. Reising or Mr. Johnstone provided a valid reason to question PECO's administrative and general and common plant cost allocations?

A. No. Both continue to argue that allocations based on labor or other costs are superior to direct assignments based on functional analysis. With respect to certain costs, Mr. Johnstone proposes a "50/50" allocation between distribution and generation without providing any back-up that such an allocation bears any relationship whatsoever to cost causation. It is a truism of ratemaking that where direct assignments can be made, they are preferable to allocations. The objective of cost allocation has traditionally been to assign costs to classes of service in a way that reflects as closely as possible each class' actual cost responsibility. When that objective can be achieved through direct assignment, allocation is unnecessary, and indeed imprudent. Now that unbundling is required, it also true that where direct assignments to the various functions (transmission, distribution, and generation) can be made, they are preferable to allocations that will necessarily bear a far looser relationship to actual cost causation.

As I explained at length in my rebuttal testimony, in response to the original claims of intervenors my colleagues and I reviewed in detail PECO's A&G and common plant accounts to determine whether PECO had inappropriately included generation-related costs in transmission and distribution costs. My purpose was to identify those costs that the transmission and distribution company would continue to incur, and which should therefore be recovered through regulated rates. When we found errors in our original assignments, we made appropriate adjustments. The result was a decrease in the distribution revenue requirement from $954.7 million to $877.1 million and the transmission revenue requirement from $165.5 million to $155.8 million. Any further reallocation of costs, particularly along the lines suggested by the opposing parties, would be inappropriate.

III. TREATMENT OF UNCOLLECTIBLES, CUSTOMER ACCOUNTS, AND SALES EXPENSE

Q. Mr. Reising continues to maintain that the production portion of uncollectible accounts expense should be removed from PECO's distribution charges. Do you agree?

A. No. My rebuttal testimony clearly shows that the recovery of all uncollectible accounts expense in distribution charges is justified. I would like to add that the level of uncollectible expense used is a pro forma amount of $65.4 million, which is approximately $22 million less than the actual 1996 test year expense of $87.5 million.

Q. Do you have any further comments regarding Mr. Reising's claims with respect to uncollectibles expense?

A. Yes. Not only does Mr. Reising improperly exclude a portion of these expenses from T&D revenue requirements, he compounds the error by allocating to these amounts additional overheads, which would further reduce T&D revenue requirements. This is completely inappropriate. Uncollectibles are unpaid bills, and nothing more.

Q. Messrs. Reising and Johnstone also seek to remove all or a portion of sales expense and customer service and information expense from distribution charges. Do you agree?

A. No. PECO, as the electric distribution company, would likely continue to incur these expenses. These are not costs incurred to carry out the "marketing" functions that will accompany generation competition, as Mr. Reising suggests. Rather, the costs in question are expenses incurred in 1996 almost entirely before Governor Ridge even signed the Electric Competition Act, and almost a year before the start of Pilot programs in the Commonwealth. Indeed, these costs include expenses associated with demand-side management and energy efficiency and audit programs, and the cost of processing high bill complaints and otherwise complying with Chapter 56 of the Commission's regulations.

IV. CLAIMS REGARDING CROSS-SUBSIDIZATION

Q. Please explain Enron's allegations regarding cross-subsidization.

A. Mr. Reising claims that as a result of what he believes are misallocations of generation-related A&G, common plant, sales and customer-related costs to transmission and distribution, PECO's competitive generation affiliates or divisions will be cross-subsidized and therefore able to sell energy at prices below market rates. Mr. Reising also suggests that, as a result of these alleged misallocations, PECO's affiliates will have an "unfair advantage" in the competitive marketplace. Mr. Mitnick reiterates Mr. Reising's claims regarding alleged cross-subsidization, but takes them one step further, suggesting that the alleged misallocations are intentional and designed to enable PECO's competitive affiliates and divisions to predatorily price and inhibit competition.

Q. Do you agree with these allegations?

A. No, for two reasons. First, there can be no cross-subsidization of PECO's competitive generation operations because PECO has not overstated transmission and distribution costs for the reasons I have explained above. Therefore, there will be no excess transmission and distribution revenues that could be used to subsidize PECO's competitive generation operations. Second, the fundamental premise that PECO's affiliates would intentionally sell below marginal cost is false and illogical.

Q. Do you have any concluding comments regarding Enron's claims of cross-subsidization?

A. Yes. The Commission has the power to scrutinize the costs incurred by PECO and PECO's competitive affiliates and divisions to ensure that PECO's affiliates are not cross-subsidized by PECO's distribution service customers. There is therefore no danger that cross-subsidization will develop in the future.

V. CONSISTENCY BETWEEN COST ALLOCATION AND RATE DESIGN

Q. Does the difference identified by Mr. Reising between the sales shown on the "Derivation of CTC/Market Price" sheets and those shown in the "Proof-of-Revenue" have any bearing on the rates developed in the "Proof-of-Revenue?"

No. The total sales shown for each rate class in the "Proof-of-Revenue" are not essential to the development of rates. It is the relative breakdown of these sales between pricing blocks which is generated by the billing sample that is important. Exhibit RAC-12, attached to this testimony, uses the GS rate class to demonstrate that the "Proof-of-Revenue" methods used historically (i.e., deriving rates at the sample level) and those used *in this* proceeding (i.e., deriving rates at the "universe" level) will produce the same rates. Accordingly, Mr. Reising's criticisms are completely unfounded.

VI. CONCLUSION

Q. Do you have any final thoughts regarding the testimony of Messrs. Mitnick, Reising, and Johnstone?

A. The purpose of their testimony regarding A&G and common plant costs, and customer-related, sales and uncollectibles expense, is to show that PECO's transmission and distribution rates are too high. I have explained already why this specific claim is incorrect. I believe, however, that it is also important for the Commission to recognize that PECO's transmission and distribution company will be incurring a substantial amount of increased fixed and operating costs to enable competitive suppliers to serve retail load that are not included in the base costs for 1996 used to develop the T&D charges and caps in the Partial Settlement. These costs will be completely unrecoverable for several years - - until the T&D rate cap expires on January 1, 2004. For example, PECO must acquire a completely new customer information and billing system to be able to properly bill customers and provide suppliers with the data they will need to serve their customers. PECO currently projects that its initial investment in this system will be more than $65 million, yielding an annual revenue requirement that PECO will not be able to recover of almost $14 million. Adding to that amount, almost $2.0 million in likely increased annual operation and maintenance expenses associated with such systems yields almost $16 million in increased annual T&D revenue requirements that PECO will not be able to recover. I note that Mr. Cohn, in his rejoinder testimony, also explains why PECO's T&D costs are likely to rise during the years when the T&D rates will be capped.

Accordingly, the proposed T&D rates are not only currently in line with T&D-related costs but are likely to under-recover PECO's actual T&D costs for the next several years.

Q. Does that conclude your rejoinder testimony?

A. Yes, it does.

SETTLEMENT PROOF OF REVENUE - Working at Sample Level

PECO Energy Company-Electric Operations
Rate GS
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Sample	Bills and kwh from sample (1)	Supplement No. 10 Bundled Pricing (2)	Revenue (3)=(1)x(2)
Customer Charge:			
1. Single Phase Customers	687,108	$8.67	$5,957,226
2. Poly Phase Customers	244,356	$23.45	$5,730,148
Customer Charge Revenue	931,464		$11,687,375
3. First 80 Hours Use	633,128,269	$0.2214	$140,174,599
4. Next 80 Hours Use-Summer	221,541,763	$0.1124	$24,901,294
5. Additional Use-Except	1,215,620,125	$0.0767	$93,238,064
6. Over 400 Hrs & 2000 kwh	53,300,420	$0.0425	$2,265,268
7. Space Heating Use	172,039,101	$0.0637	$10,958,891
Energy Rate Revenue	2,295,629,678		$271,538,115
8. Total Sample Revenue			$283,225,490
Universe Revenue			$ 761,508,000
Universe to Sample Revenue Ratio			2.68870

	Bills and kwh from sample (1)	NEW Unbundled Pricing (2)	Revenue (3)=(1)x(2)	Universe to Sample Ratio	Universe Revenue
FIXED DISTRIBUTION					
	687,108	$8.67	$5,957,226		
	244,356	$23.45	$5,730,148		
	931,464		$11,687,375		
VARIABLE DISTRIBUTION					
	633,128,269	$0.0387	$24,513,009		
	221,541,763	$0.0183	$4,059,219		
	1,215,620,125	$0.0116	$14,152,592		
	53,300,420	$0.0052	$279,318		
	172,039,101	$0.0092	$1,584,412		
	2,295,629,678		$44,588,548	2.68870	$ 151,309,000
TRANSMISSION					
	633,128,269	$0.0131	$8,312,200		
	221,541,763	$0.0062	$1,376,502		
	1,215,620,125	$0.0039	$4,798,976		
	53,300,420	$0.0018	$94,841		
	172,039,101	$0.0031	$537,435		
	2,295,629,678		$15,119,954	2.68870	$ 40,653,000
CTC					
	633,128,269	$0.0950	$60,150,288		
	221,541,763	$0.0450	$9,960,209		
	1,215,620,125	$0.0286	$34,727,209		
	53,300,420	$0.0129	$685,834		
	172,039,101	$0.0226	$3,887,754		
	2,295,629,678		$109,411,293	2.68870	$ 294,174,000
MARKET ENERGY AND CAPACITY					
	633,128,269	$0.0500	$31,628,153		
	221,541,763	$0.0313	$6,927,108		
	1,215,620,125	$0.0251	$30,569,654		
	53,300,420	$0.0193	$1,028,001		
	172,039,101	$0.0229	$3,942,780		
	2,295,629,678		$74,095,696	2.68870	$ 199,221,000
			$254,902,866	2.68870	$685,357,000

1 The ratio of universe revenue to sample revenue is calculated. NOTE: The relationship of universe sales to sample sales is never considered.

2 Each of the unbundled revenue requirement components (from annual summary sheets) is reduced by the universe/sample revenue ratio to convert them to "sample size."

3 The "sample size" revenue is spread to each block and for each block the revenue is divided by the sales to determine the rate.

SETTLEMENT PROOF OF REVENUE - Working at "Universe" Level

PECO Energy Company-Electric Operations
Rate GS
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Sample	Bills and kwh from sample (1)	Supplement No. 10 Bundled Pricing (2)	Revenue (3)=(1)x(2)
Customer Charge:			
1. Single Phase Customers	1,847,430	$8.67	16,017,214
2. Poly Phase Customers	657,001	$23.45	15,406,669
Customer Charge Revenue	2,504,431		$31,423,883
3. First 80 Hours Use	1,702,294,084	$0.2214	376,887,910
4. Next 80 Hours Use-Summer	595,660,075	$0.1124	66,952,192
5. Additional Use-Except	3,268,441,875	$0.0767	250,689,492
6. Over 400 Hrs & 2000 kwh	143,309,017	$0.0425	6,090,633
7. Space Heating Use	462,562,103	$0.0637	29,465,206
Energy Rate Revenue	6,172,267,154		$730,085,433
8. Total Sample Revenue			$761,509,316
Universe Revenue			$ 761,508,000
Universe to Sample Revenue Ratio			1.00000

1 The universe revenue and the "universe" sales are used from the start. NOTE: The "universe" sales of 6,172,267,154 kWh do not match the pro-forma sales of 6,596,721,000 kWh but the rates calculated are identical.

	Bills and kwh from sample (1)	NEW Unbundled Pricing (2)	Revenue (3)=(1)x(2)	Universe to Sample Ratio	Universe Revenue
FIXED DISTRIBUTION					
	1,847,430	$8.67	16,017,214		
	657,001	$23.45	15,406,669		
	2,504,431		$31,423,883		
VARIABLE DISTRIBUTION					
	1,702,294,084	$0.0387	$65,908,306		
	595,660,075	$0.0183	$10,913,724		
	3,268,441,875	$0.0116	$38,051,682		
	143,309,017	$0.0052	$751,354		
	462,562,103	$0.0092	$4,260,050		
	6,172,267,154		$119,885,116	1.00000	$ 151,309,000
TRANSMISSION					
	1,702,294,084	$0.0131	$22,349,483		
	595,660,075	$0.0062	$3,700,840		
	3,268,441,875	$0.0039	$12,903,312		
	143,309,017	$0.0018	$254,784		
	462,562,103	$0.0031	$1,444,582		
	6,172,267,154		$40,653,001	1.00000	$ 40,653,000
CTC					
	1,702,294,084	$0.0950	$161,725,745		
	595,660,075	$0.0450	$26,780,088		
	3,268,441,875	$0.0286	$93,371,186		
	143,309,017	$0.0129	$1,843,672		
	462,562,103	$0.0226	$10,453,308		
	6,172,267,154		$294,173,999	1.00000	$ 294,174,000
MARKET ENERGY AND CAPACITY					
	1,702,294,084	$0.0500	$85,039,472		
	595,660,075	$0.0313	$18,625,151		
	3,268,441,875	$0.0251	$82,192,913		
	143,309,017	$0.0193	$2,763,563		
	462,562,103	$0.0229	$10,601,285		
	6,172,267,154		$199,222,384	1.00000	$ 199,221,000
			$685,358,383	1.00000	$685,357,000

PECO STATEMENT NO. 26-RJ

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

EXTRA COPY

APPLICATION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

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PROTHONOTARY'S OFFICE

REJOINDER TESTIMONY

OF

MICHAEL S. FREEMAN

Regarding Retail Market Prices

Oct. 8, 1997

PECO STATEMENT EXHIBIT 26-RJ
DATE 10-16-97
MARY ELLEN WOLF, REPORTER

Philadelphia
R-00973953, etc.

REJOINDER TESTIMONY OF MICHAEL S. FREEMAN

Q. Please state your full name and business address.

A. Michael S. Freeman, 2301 Market Street, S7-3, Philadelphia, PA 19103.

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

A. I am employed by PECO Energy Company ("PECO" or "the Company") as a supply manager on PECO's National Energy Team. The National Energy Team contracts with customers who have facilities in multiple locations, offering electricity and fuel brokering, billing, metering, and demand-side management services. My job is to provide analytical support for electricity pricing offers and to make supply arrangements at the lowest cost possible. PECO's National Energy Team is active in regions where retail access has begun or is about to begin, including the PJM area, New England, and California.

Q. Please state your educational background and experience.

A. My resume is attached as Exhibit MSF-1.

Q. Have you testified previously before the Commission?

A. Yes. I testified in 1995 in a case involving PECO's Large Interruptible Load Rider (LILR). In that case, PECO obtained the Commission's approval to freeze the availability of the LILR.

Q. What is the purpose of your testimony?

A. I am testifying as to the reasonableness of the energy and capacity caps contained in the proposed Partial Settlement from both a wholesale and retail perspective. I will show that current wholesale energy and capacity transactions are in line with or below the energy and capacity caps set forth in the proposed Partial Settlement. I will then discuss retail transactions that have been proposed or executed by competitive suppliers in PECO's service territory and elsewhere. These transactions demonstrate that a competitive market with discounted prices for customers is in fact emerging.

Q. What is your understanding of the opposing parties' position relative to the energy and capacity rate caps contained in the Partial Settlement?

A. Witnesses for Enron and MAPSA contend that the actual retail market price will be above those capped rates, at least in some of the early years of the transition period.

Q. Do you agree?

A. No. First, I would note that, although such arguments were advanced by the same suppliers in in PECO's Pilot Program, these suppliers have helped enroll approximately 93,000 customers in the Pilot, already have made supply offers to customers, and will be making many more offers by the sign-up deadline, which is October 25, 1997.

Second, the Electric Competition Act contemplates a phase-in of retail access, not an immediate transition. The general approach taken by competitive suppliers thus far in Pennsylvania and New England parallels this sense of the pace of retail access. In other words, my experience is that suppliers have been much more willing to use the price caps as a hedge, with any savings generated below the standard offer split between the supplier and the customer, instead of offering customers fixed or indexed rates.

Third, and most importantly, the energy and capacity rate caps in the Partial Settlement are reasonable relative to cost-based projections of energy and capacity prices, as well as market experience. All of us who are involved in the development of retail access in Pennsylvania have little to no experience in delivering competitive power to retail customers in Pennsylvania. Therefore, we rely upon cost-based market projections and experience in PJM and elsewhere, such as New England. But it is possible that the results of cost-based modeling and current experience may not tell the whole story. In the Pilot Program, for instance, PECO's wholesale marketing division, the Power Team, has provided standard products for competitive suppliers. The Power Team will charge suppliers an all-in price for energy and capacity, including line losses, reserve margin, load-following costs, and Gross Receipts Tax, exactly equal to the generation credit that is being extracted from participating customers' bills. However, the Power Team stated in its solicitation letter that it reserves the right to discount the offer. Additionally, the Power Team included a solicitation of market-based bids to procure energy and/or capacity products "for the specific purpose of supplying retail loads won in any and all Pennsylvania Retail Pilots." Therefore, bilateral arrangements that are made as a result of these solicitations may create savings for suppliers and their customers below the generation credit. Additionally, other generators may want to break into the PJM market, creating competitive pressure that does not exist today.

The phase-in of retail access means we are all on a ramped-up schedule – competitive suppliers as well as customers. The energy and capacity caps should not be set at a level such that competitive suppliers can experience a windfall from the outset of retail access. The pricing design that I described above – that is, shared savings if the supplier can procure energy and capacity for less than the energy and capacity cap -- represents a market outlook that places value on gaining a foothold by signing customers to low-risk contracts. As the market gains momentum and experience, the suppliers' outlook holds that they will be able to "beat" the generation cap and generate a positive cash flow. At that point, other pricing designs likely will be offered, along with non-commodity offers of products and services such as billing, metering, and other energy services. Customers who place a value on such services may be willing to pay a little more than the energy and capacity caps.

Q. As to your third point, is the energy price projected by Dr. Hieronymus for 1999 supported by current energy prices in PJM?

A. Yes. Dr. Hieronymus projects an average price of $20.2/MWh for 1999. Actual all-hours energy prices in PJM, as reported in the Power Market Week summary, averaged $20.34/MWh for the period January, 1997 through October 3, 1997. The on-peak average for that same period was $25.69/MWh, while the off-peak average was $15.74/MWh.

Q. Has PECO entered into wholesale contracts that confirm the capacity prices projected by Dr. Hieronymus?

A. Yes. PECO has contracts for the purchase and/or sale of capacity within PJM at prices that are equal to or less than the $16/kilowatt-year capacity price projected by Dr. Hieronymus for 1999.

Q. Based on your knowledge of the wholesale prices currently being experienced in PJM, are the wholesale prices projected by Dr. Hieronymus reasonable?

A. Yes. The PJM region already has one of the most liquid wholesale markets of any region of North America. Current prices reflect many purchases and sales of both energy and capacity. Therefore current prices accurately reflect the ability to purchase energy and capacity in the PJM region and accurately reflect the wholesale prices available to any potential competitive supplier under deregulation. Current prices confirm that the price projections of Dr. Hieronymus are reasonable.

Q. What retail offers in Southeastern Pennsylvania are you aware of?

A. I am aware that Strategic Energy Partners Limited (SEL), a marketer licensed by the PUC to supply retail service in Pennsylvania, has offered a commercial customer an arrangement under which SEL will take 10% of the difference between the delivered price and the standard offer, or 1 mill per kilowatt-hour, whichever is lower. In addition, New Energy Ventures (NEV) has given customers in PECO's territory a one-page description of what it calls a "Group Member Agreement Summary," a three-year arrangement under which NEV retains 25 percent of the "difference of the member's total bill from NEV and the bill had the member received equivalent services from its local electric utility under the appropriate tariff." The agreement also states that NEV will match any price below NEV's price, or NEV will "allow the member to make the purchase directly."

The outlook that drives all of these deals is, I believe, an optimistic view of the future marketplace. A company such as NEV can essentially use the caps as a hedge, with only the firm's transactions costs for billing and other customer services at risk. NEV obviously has an expectation that, at some point during the term of this arrangement, it can generate savings for customers and payments for itself.

I am also aware of a retail pilot offer that was made to a high load factor, industrial firm in PECO's territory that was framed as a guaranteed discount of 10 percent below the customer's PECO bill. Since the Customer Participation Credit for this customer's tariff would provide a guaranteed reduction of only 6 or 7 percent, the supplier must discount the commodity charge by about 2 or 3 mills per kWh to achieve the total discount of 10 percent.

Q. Are you aware of retail prices being offered outside of PJM?

A. Yes. For example, NEV has been successful in the California market in signing customers to discounted supply arrangements. The standard offer in California is a rolling four-week average of the all-hours Power Exchange price, applied to the average load shape of each rate class. NEV signed a one-year deal with the Association of California Water Agencies Utility Service Agency that "will result in significant savings . . . Our members can choose either a guaranteed discount from utility retail rates or a very attractive share-the-savings arrangement," according to a statement issued by the Agency. In Rhode Island, where the standard offer in 1998 is 2.80 cents per kWh, NEV signed up Providence Metallizing, a metal finishing company that will "lower its energy costs significantly because of its contract with New Energy Ventures," according to Barbara Gates-Garnick, president of NEV-New England. "We are very confident that we can cut energy bills for New Energy Ventures clients."

Q. What prices have been offered to customers in the New England pilot programs?

A. In the summer of 1996, when New England Power Pool average energy rates were running at \$22 to \$23 per megawatt-hour, suppliers offered a variety of retail deals that were at or just above the wholesale energy prices. For example, Wheeled

Electric Power delivered retail power at 2.29 cents per kWh. Granite State Energy offered 2.5 cents per kWh for anyone who signed up for two years. Enron offered the town of Peterborough, New Hampshire a $25,000 donation for public works projects and power at 2.29 cents per kWh to every resident. In a response to an interrogatory from State Sen. Vincent J. Fumo in this proceeding, Enron stated that it is selling retail power in New Hampshire for a weight-averaged delivered price of 2.53 cents per kWh. In short, in all of these examples, the spread between wholesale costs and retail prices was very thin, suggesting that alternative suppliers may have been willing to forego some of the "mark-up" which the opposing parties are proposing in this proceeding.

Q. Does this conclude your testimony?

A. Yes.