R-00973953, R-00973953C0001-C0007

PAIEUG STATEMENT NO. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
V.	)	DOCKET NO. R-00973953
PECO ENERGY COMPANY	)	
APPLICATION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	)	

DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

JUNE 1997

BEFORE THE

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 35 Glenlake Parkway, Suite 475, Atlanta, Georgia 30328.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Bachelor of Business Administration in Accounting from the University of Toledo. I also received a Master of Business Administration from the University of Toledo. I am a Certified Management Accountant ("CMA") and a Certified Public Accountant ("CPA").

Since 1986, I have held various positions with Kennedy and Associates. I specialize in revenue requirements analyses, taxes, the evaluation of rate and financial impacts of traditional and non-traditional ratemaking, and other utility strategic, operational, financial, and accounting issues.

From 1983 to 1986, I held various positions with the consulting group at Energy Management Associates. I specialized in utility finance, utility accounting issues, and computer financial modeling. I also directed consulting and software projects utilizing PROSCREEN II and ACUMEN proprietary software products to support utility rate case filings, budgets, internal management and external reporting, and strategic and financial analyses.

From 1976 to 1983, I held various positions with The Toledo Edison Company in the Accounting and Corporate Planning Divisions. From 1980 to 1983, I was responsible for the Company's financial modeling and financial evaluation of the Company's strategic plans. In addition, I was responsible for the preparation of the capital budget, various forecast filings with regulatory agencies, and assistance in rate and other strategy formulation. I utilized the strategic planning model PROSCREEN II, the production costing model, PROMOD III, and other software products to evaluate capacity swaps, sales, sale/leasebacks, cancellations, write-offs, unit power sales, and long term system sales, among other strategic options. From 1976 to 1980, I held various other positions in the Budget and Accounting Reports, Property Accounting, Tax Accounting, and Internal Audit sections of the Accounting Division.

I have appeared as an expert witness on regulatory accounting, finance, and planning issues before regulatory commissions and courts in numerous states on more than one hundred occasions. I have appeared as an expert witness before the Pennsylvania Public Utility Commission in Docket Nos. M-87017-1C001, M-87017-2C005, R-891364, P-910511, P-910512, R-922314, R-922378, R-922479, R-943271, and R-973877. In addition, I have developed and presented papers at various industry conferences on utility rate, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in my Exhibit ____(LK-1).

Q. Please describe the firm of Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric, gas, and telecommunications utilities industries. The firm provides expertise in utility industry restructuring and transition issues, financial analysis, revenue requirements, cost of service, rate design, system planning and load forecasting. Clients include industrial electricity and gas consumers and state government agencies.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Philadelphia Area Industrial Energy Users Group ("PAIEUG"), a group of large industrial customers taking service on the PECO Energy Company ("PECO" or "Company") system.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is:

- To address and make recommendations regarding the treatment of regulatory assets and liabilities included by PECO in its filing and those that it failed to include in its filing as stranded cost components of the competitive transition charge ("CTC").

- To address and make recommendations regarding the appropriate level of fossil decommissioning includable as a stranded cost component of the CTC.

- To address and make recommendations regarding the appropriate level of nuclear decommissioning and the related tax effects includable as a stranded cost component of the CTC.

- To address and make recommendations regarding the appropriate level of other transition costs includable as a stranded cost component of the CTC.

- To address and make recommendations regarding the appropriate discount rates to utilize for the net present value computations incorporated in the stranded cost determinations.

Q. Please summarize your testimony.

A. The following table summarizes the PAIEUG recommendations compared to PECO's request in this proceeding for recovery by PECO through the CTC of its regulatory assets and liabilities, fossil decommissioning, nuclear decommissioning, and other claimed transition costs. These amounts were also provided to PAIEUG witness Mr. Baron for his summary and computations related to the complete quantification of PECO stranded costs and the structure and timing of recovery. The PAIEUG amounts represent the net present value at December 31, 1998 of each properly claimable cost for those issues affirmatively addressed by PAIEUG.

PECO RESTRUCTURING
REGULATORY ASSETS AT 12/31/98
SUMMARY
($000)

Description	PECO	PAIEUG	
SFAS 109	1,687,069	736,153	
Deferred Fuel	311,468	96,162	
CC on 50% Limerick Common	175,812	175,812	(1)
Unamortized Loss on Reacquired Debt	158,311	158,311	(1)
Pension Overfunding	0	(217,347)	
SFAS 106	100,580	(130,467)	
Limerick 1 Declaratory Order	18,301	14,305	
Limerick 2 Declaratory Order	67,985	53,141	
CC on 50% Peach Bottom/Salem/Eddy Common	17,400	17,400	(1)
Nuclear Design Basis Documentation	28,852	0	
Peach Bottom/Limerick Water Chemistry	6,692	0	
Compensated Absences	16,587	16,587	(1)
Total Regulatory Assets	2,589,057	920,057	
Fossil Decommissioning	126,605	0	
Nuclear Decommissioning	236,929	(140,410)	
Other Transition Costs	32,661	25,530	
Total	2,985,252	805,177	

Notes: (1) PAIEUG has not addressed these issues and does not affirmatively support these PECO issues or PECO's quantifications.

In conjunction with my recommendation regarding the nuclear decommissioning regulatory asset reflected on the preceding table, I also recommend that the Commission utilize future nuclear decommissioning accruals that reflect earnings on trust fund balances post-retirement until disbursed and that reflect fully all federal and state tax benefits available to PECO. I have provided the revised annual nuclear decommissioning expense accruals to Mr. Falkenberg and he has incorporated them into his quantifications of market value and stranded generation costs.

Finally, I recommend that the Commission utilize a discount rate of 7.60% for the computation of market value and generation stranded costs, and a discount rate of 7.23% and grossed up rate of return of 12.35% to compute the annual CTC revenue requirement effects of the stranded cost recovery. The two discount rates are identical to the two rates proposed by PECO in its filing for these purposes except that I incorporated the 10.0% DCF return on common equity from the Commission's Order in the PECO QRO proceeding. I have provided the first discount rate to PAIEUG witness Mr. Falkenberg and the second discount rate along with the grossed up rate of return to Mr. Baron for use in their respective computations.

Q. What general principles guided your evaluation of PECO's request for stranded regulatory assets and liabilities?

A. The following general principles, grounded in regulatory theory and incorporated in the Electricity Generation Customer Choice and Competition Act (the "Competition Act"), guided my evaluation.

- The costs must represent those that would otherwise be recoverable as a cost of service under traditional regulation.

- The costs must be known and measurable.

- Only the net of regulatory assets and liabilities is recoverable.

- The net regulatory assets must be stated on a net present value basis.

- Any resulting rates must be just and reasonable.

The primary provisions of the Competition Act that I have relied upon for these principles are as follows:

> **§2803. Definitions. " 'Transition or stranded costs.' An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the Commission determines will remain following mitigation by the electric utility. This term includes:**
>
> > **(1) Regulatory assets and other deferred charges typically recoverable under current regulatory practice, the unfunded portion of the utility's projected nuclear generating plant decommissioning costs and cost obligations under contracts with nonutility generating projects which have received a Commission order, the recoverability of which shall be determined under § 2808(C)(1) (relating to Competitive Transition Charge)."**

> **§2804(13). "Consistent with § 2808 (relating to Competitive Transition Charge), the Commission has the power and duty to approve a Competitive Transition Charge for the recovery of transition or stranded costs it determines to be just and reasonable to recover from ratepayers."**
>
> **§2808(C). Determination of Competitive Transition Charge. "In determining the level of transition or stranded costs that an electric utility may recover through the Competitive Transition Charge, the Commission shall apply the following principles:**
>
> > **(1) The Commission shall allow recovery of regulatory assets and other deferred charges typically recoverable under current regulatory practice . . .**
> >
> > **(3) The Commission shall determine the level of other generation-related transition or stranded costs that may be recovered through the Competitive Transition Charge."**

Q. Were there other principles that guided your evaluation of PECO's request for specific regulatory assets and liabilities, fossil decommissioning, nuclear decommissioning, and other transition costs?

A. Yes. However, these principles are discussed in the subsequent sections since application is specific to the individual costs.

Q. How is the remainder of your testimony structured?

A. The remainder of my testimony follows the sequence of the issues listed on the summary table comparing the PAIEUG recommendations to those in PECO's filing. However, I have no additional testimony on the following regulatory asset issues:

- Carrying charges on 50% of Limerick Common.
- Unamortized loss on reacquired debt.
- Carrying charges on 50% of Peach Bottom, Salem, Eddy Common.
- Compensated absences.

In addition to the regulatory assets and other issues identified in the preceding table, I address the nuclear decommissioning tax effects and future expense accruals in conjunction with the nuclear decommissioning regulatory asset issue and the appropriate discount rates and grossed-up rate of return in subsequent sections of my testimony.

II. SFAS 109

Q. Please describe the requirements of SFAS 109 and PECO's implementation of that accounting standard.

A. SFAS 109 is an accounting requirement that requires companies, including PECO, to recognize its future income tax payments as a deferred income tax liability on its accounting books and balance sheet. To the extent that PECO had not previously recovered and recognized its accumulated deferred tax liability for temporary differences between book and tax accounting, SFAS 109 required PECO to create a second balance of accumulated deferred income taxes. SFAS 109 also required that regulated utilities such as PECO record a third balance of accumulated deferred income taxes recognizing the income tax gross up on the second balance that would be necessary for it to collect in future revenues to make the tax payments represented by the second balance.

PECO then created a SFAS 109 regulatory asset equivalent to the sum of the newly recognized second and third accumulated deferred tax liabilities required by SFAS 109. That SFAS 109 regulatory asset is stated on a revenue requirement basis.

Q. **Please describe the Company's SFAS 109 regulatory asset included in its computation of stranded costs.**

A. The Company has included the gross SFAS 109 deferred asset on a nominal basis at December 31, 1998. The Company's quantification of the SFAS 109 regulatory asset is detailed in a series of computations on two separate sets of documents. The Company first computed a December 31, 1996 SFAS 109 regulatory asset of $1,932.585 million reflecting the revenue requirement effect of the unrecovered tax effects of generation plant related temporary book-tax differences. This computation of the December 31, 1996 amount was provided in response to OCA-III-17 and is replicated and attached as my Exhibit___(LK-2). This balance was then reduced for certain offsets to $1,919.352 million at December 31, 1996 before reduction for 1997 and 1998 estimated amortizations. The 1997 and 1998 amortizations are detailed on PECO Exhibit ABC-1, Schedule 6 pages 1 and 3 of 3.

The Company then assumed that the SFAS 109 regulatory asset would be amortized and recovered over the seven year CTC recovery period. Although PECO did not state the SFAS 109 regulatory asset on a net present value basis, the Company does recognize that its claim is stated on a nominal dollar basis. As such, PECO witness Alan Cohn did not include a return on the unamortized SFAS 109 balance in the quantification of the Company's seven year levelized CTC annual revenue requirement detailed on PECO Exhibit ABC-1, Schedule 10 pages 1 and 4 of 5.

Q. **Is the Company's quantification of the SFAS 109 regulatory asset correct?**

A. No. First, PECO failed to state the SFAS 109 regulatory asset on a net present value basis as is required under the Competition Act. Second, PECO incorrectly assumed that the net present value effect on its CTC revenue requirement computation should be the direct result of the CTC recovery period rather than the number of future years over and in the pattern of which it would have been entitled to recover these costs under traditional regulation, another requirement of the Competition Act.

Q. **Is it appropriate to assume for purposes of quantifying the net present value of the SFAS 109 regulatory asset a straight line amortization and discounting based upon the seven year period as proposed by PECO?**

A. No. The SFAS 109 regulatory asset at December 31, 1998 is the nominal value of future revenue collections from ratepayers for temporary/timing differences to which the Company is entitled over the lives of the underlying generating units. These units are projected by PECO to continue operating on a net plant weighted basis for another 26.9 years beyond January 1, 1999. Thus, in order to quantify the "value" of the SFAS 109 regulatory asset under traditional regulation, the quantification must be based upon the future amounts and pattern of recovery to which the Company is entitled.

Q. **What impact should the CTC recovery period have on the quantification of the SFAS 109 regulatory asset?**

A. The recovery period should have no impact whatsoever on the net present value quantification of the SFAS 109 regulatory asset. The quantification of the December 31, 1998 net present value is a function of the time period and pattern of recovery under traditional regulation, and not the CTC recovery period as proposed by PECO.

If PECO's proposal were correct, then logically it would be entitled to a net present value equal to the nominal value of $1,687.069 million on December 31, 1998 assuming instantaneous recovery. It would be entitled to a net present value on December 31, 1998, of $1,318.709 million assuming seven year recovery, and it would be entitled to a net present value on December 31, 1998 of $1,194.950 million assuming ten year recovery. Obviously, the net present value cannot be and should not be a function of the CTC recovery period, but rather independently should be computed based upon its entitlement under traditional regulation.

Q. Has the Company incorporated its "net present value over the CTC recovery period" theory in its quantification of the investment tax credit regulatory liability?

A. No. The Company selectively employed its theory of computing the net present value over the recovery period to increase its stranded cost quantification. In stark contrast to PECO's SFAS 109 application of this theory, the Company utilized a "net present value over the life of the assets theory" for its quantification of the investment tax credit regulatory liability. In its quantification of stranded generation costs, PECO computed the net present value of the investment tax credit regulatory liability over the underlying assets' remaining life <u>under traditional regulation</u>. That treatment had the effect of reducing the $263 million nominal value of this regulatory liability to only $137.345 million.

Thus, the Company has utilized inconsistent net present value theories, both of which serve to increase the Company's total stranded cost computation compared to the consistent use of one or the other.

Q. Has the Company incorporated its "net present value over the CTC recovery period" theory in its quantification of the future tax benefits regulatory liability?

A. No. Again, the Company has selectively employed its theory of computing the net present value over the recovery period to increase the level of SFAS 109 regulatory asset recovery compared to its treatment of tax related regulatory liabilities under the "net present value over the life of the assets theory." Similar to its treatment of the accumulated deferred investment tax credit, PECO computed the net present value of the future tax benefits over the underlying assets' remaining life under traditional regulation. This further illustrates the Company's utilization of inconsistent net present value theories, the net effect of which is to increase its total stranded cost quantification.

Q. Is the Company's "net present value over the CTC recovery period" theory for the SFAS 109 regulatory asset consistent with the Pennsylvania Power & Light Company ("PP&L") treatment in its recent restructuring filing before the Commission in Docket No. R-973954?

A. No. To the contrary, PP&L appropriately 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. I have replicated the summary pages from PP&L's restructuring filing that demonstrate its treatment as my Exhibit ____(LK-3).

Q. Have you quantified the net present value of the net SFAS 109 regulatory asset?

A. Yes. The present value of the net SFAS 109 regulatory asset at December 31, 1998 is $736.153 million. I utilized a 7.60% discount rate applied to the future annual level and pattern of SFAS 109 amortizations and recoveries under traditional regulation over the remaining average life of 23 years. The computations are detailed on my Exhibit ____(LK-4).

Q. Will the PAIEUG recommendation to compute the net present value of the regulatory asset over the underlying remaining lives of the generating units require PECO to recognize an immediate writeoff or writedowns of its SFAS 109 book accounting asset?

A. In my opinion, it will not. The SFAS 109 balance is stated on the Company's balance sheet on a nominal basis. The regulatory asset included in the stranded cost quantification must be stated on a net present value basis, in accordance with the requirements of the Competition Act. The valuation on a net present value basis is dependent upon the nominal balance that must be recovered, the discount rate, and the time period over which the future tax amounts should be reflected. The major difference between the Company and PAIEUG is on the time period to be used for the valuation on a net present value basis.

The Company's CTC revenue requirement computations reflect an imputed net present value based upon straightline amortization over seven years. PECO will not be required to recognize an immediate writeoff or writedown under its seven year theory, nor has it made any such allegations.

The PAIEUG valuation reflects a net present value based on straightline amortization over the underlying lives of the generating units, consistent with the expected collection of PECO's future tax entitlements under traditional regulation, as required under the Competition Act. The PAIEUG position reflects the continuation of traditional regulation. If no writeoff or writedown has been required under the traditional regulatory process, then no writeoff or writedown should be required under a valuation approach that is predicated upon the traditional regulatory process.

III. DEFERRED FUEL

Q. Please describe the Company's request for recovery of deferred fuel costs as a regulatory asset in its CTC stranded cost quantification.

A. The Company's computation of this regulatory asset consists of three components as described on pages 28 through 30 of Mr. Cohn's direct testimony. The first component is the $92.000 million amount of deferred fuel ($69.700 million) and nuclear performance bonus ($22.3 million) actually recognized on the Company's accounting books and financial statements at December 31, 1996. The second component is the additional amount of deferred fuel at $22.0 million annually plus interest at 9% through December 31, 1998 sought by the Company in Docket Nos. P-00961128 and R-00963838 and the subject of a Tentative Order issued by the Commission. The third component is the Company's projection of an additional seven years of deferred fuel at $22.7 million annually through December 31, 2005 and also the subject of the referenced Tentative Order issued by the Commission.

Q. Since the Commission issued its Tentative Order in the referenced dockets, has it issued a final opinion and order?

A. Yes. The Final Order was issued on May 22, 1997. That order included specific language that PECO had the burden of proof to demonstrate in its restructuring proceeding that indeed it had or would undercollect its fuel costs. That order also stated that the computational basis for undercollected fuel costs considered to be regulatory assets after December 31, 1996 would be deferred to and determined in the Company's restructuring proceeding.

Q. Is it appropriate to include the first component of the Company's deferred fuel regulatory asset in the CTC stranded cost quantification?

A. Yes. The Company's computation of the deferred amount at December 31, 1996 appears to properly approximate its entitlement to recover unrecovered fuel costs through the ECA had it not been rolled into base rates. This includes the amount deferred as of December 31, 1995 plus the amount deferred in 1996.

Q. Is it appropriate to include the second component in the CTC stranded cost quantification?

A. No. First and fundamentally, there is no factual foundation in the Company's filing that it has or will underrecover its 1997 and 1998 fuel costs compared to the amount that was rolled into base rates. Thus, the Company has failed to justify or demonstrate the "prudence and reasonableness of the accuracy and propriety of these undercollections," the standard set out for the Company by the Commission in the referenced Order in order to obtain recovery of deferred amounts through the CTC.

Second, the Company's quantification of the annual $22.0 million deferral sought was based upon a five year historic average of fuel costs. The five year historic average fuel costs are not a proper measure of 1997 and 1998 actual fuel costs, the computation basis for the former ECR prior to the roll-in to base rates. The five year average would equal the 1997 and 1998 actual fuel costs only by coincidence. Thus, the $22.0 million annual deferral amount is not known and measurable and does not qualify for CTC recovery.

Q. **Is the inclusion of the third component of the Company's deferred fuel regulatory asset in the ITC stranded cost computation appropriate?**

A. No. The same reasons are applicable for excluding the third component as the second component. In addition, the third component representing alleged annual underrecoveries of $22.0 million from 1999 through 2005 is even more speculative and further removed from the 1996 test year utilized by the Company and the Commission in the previously referenced dockets. Whether there will be underrecoveries or overrecoveries in the years 1999 through 2005 is sheer speculation. Thus, the $22.0 million annual deferral amount is not known and measurable and does not qualify for CTC recovery.

Further, commencing in 1999, generation in Pennsylvania will be unbundled and the CTC will be in effect. Generation costs will be no longer cost based but rather market based. There will be no longer a cost based revenue requirement determination for generation. Thus, the Company's request for this third component represents an illusory and improper regulatory asset and does not qualify as a transition or stranded cost.

IV. PENSION OVERFUNDING

Q. Please describe PECO's treatment of its excess pension fund assets in its stranded cost quantification.

A. Despite substantial overfunding coupled with continued overcollections in base rates, the Company has failed to treat its excess pension fund assets as a regulatory liability. At December 31, 1996, the fair value of the pension plan assets was $2,087.428 million compared to the accumulated benefit obligation of $1,786.592 million and the actuarial present value of accumulated plan benefits of $1,666.358 million. These amounts were obtained from the Company's most recent pension actuarial report provided as the Company's Schedule C-7 response to the Commission's filing requirements. In that actuarial report, the accumulated benefit obligation was utilized to determine the plan's funding status on the basis of SFAS 87. The actuarial present value of accumulated plan benefits was utilized to determine the plan's funding status on the basis of SFAS 35.

Q. Have you quantified the excess funding on a generation basis?

A. Yes. The excess pension plan funding on a generation basis is $217.347 million at December 31, 1998. I assumed that the generation portion of the excess was the same as the generation allocation percentage of 52.5% and the electric allocation percentage of 94.0% for SFAS 106 costs, as detailed on PECO Exhibit ABC-1 Schedule 6 page 2 of 3.

Q. Why is it appropriate to treat the excess pension funding as a regulatory liability for purposes of the stranded cost quantification?

A. This overfunding represents a "savings account" that can be utilized by the Company to either offset future pension expense or to withdraw in some manner, albeit with certain limitations and penalties. Nevertheless, this savings account represents a prepayment by ratepayers through past revenue recovery of pension expense by PECO for which ratepayers are entitled to full credit in the stranded cost quantification.

Q. Does this regulatory liability actually exist?

A. Yes. This regulatory liability can be readily contrasted to the Company's claim for recovery of a deferred fuel regulatory asset for costs it alleges will be unrecovered after December 31, 1998. In that case, the Company's future deferred fuel regulatory asset is a conceptual and computational myth dependent upon projections of fuel costs equivalent to the average of the 1992-1996 ECR costs. In the case of the pension overfunding, the computation is a reality, as measured by accounting and actuarial professionals, is disclosed in its financial statements and notes, and is not dependent upon the logical stretches of the Company's deferred fuel claim.

Q. Does the pension overfunding represent a net present value amount?

A. Yes. Consequently, no discounting is necessary to state the amount on a net present value basis at December 31, 1998 for purposes of the stranded cost quantification.

V. SFAS 106

Q. Please describe SFAS 106.

A. SFAS 106 is an accounting requirement, effective for years 1993 and after, that required companies, including PECO, to recognize its postretirement benefits expense on an accrual basis, rather than on a cash pay-as-you-go basis. SFAS 106 provided detailed direction on the accrual expense computation and the recognition of plan assets and liabilities. SFAS 106 expense consisted of several components including the recognition of a transition obligation for costs allocable to earlier periods. The transition obligation could be recognized through either a one-time charge or through amortizations included in the SFAS 106 accrual expense computation over as many as 20 years. The unrecognized transition obligation is not reflected as a liability on the balance sheet.

The SFAS 106 accrual expense consists of the sum of the amortizations of and interest on the transition obligation and the expense recognized for current employee service reduced by the return on plan assets.

Q. Was PECO required to adopt SFAS 106 in 1993?

A. Yes. PECO adopted SFAS 106 in 1993 for book accounting purposes. PECO filed with the Pennsylvania Public Utility Commission to increase its rates by $50.2 million to reflect a claimed increase in expense due to the excess of the SFAS 106 over the cash pay-as-you-go annual expense. It also sought authority from the Commission to defer its excess SFAS 106 over cash pay-as-you-go expenses for the 1993-1994 period. In 1995, the case was settled. PECO was allowed to increase its base rates by $25 million, and to establish a regulatory asset for the nominal value of the 1993 and 1994 SFAS 106 expenses in excess of cash pay-as-you-go. The settlement also stated that with the increase in base rates, PECO's base rates fully recovered its SFAS 106 expenses.

Q. Did the settlement in 1995 of the SFAS 106 proceeding address the effects of the Company's 1994 early retirement programs on its accounting for SFAS 106 costs or the ratemaking treatment?

A. No. Despite the fact that the early retirement programs already had been implemented and the accounting implications already considered and decided by the Company, the settlement did not address the Company's accounting treatment of the 1994 early retirement programs on the Company's SFAS 106 expenses.

Q. How did the Company account for the SFAS 106 unrecognized transition costs associated with the early retirement programs?

A. It recognized as a transition obligation the previously unrecognized liability, effectively accelerating 18 years of future amortization into the immediate recognition of a liability. To avoid the expense writeoff that would have been required, PECO unilaterally created a deferred asset for an amount equivalent to the newly recognized liability. Each year subsequent to 1994, PECO has amortized a portion of the SFAS 106 deferred asset to postretirement benefits expense.

Q. Please describe the Company's request for a SFAS 106 regulatory asset to be included in its CTC stranded cost quantification.

A. PECO has requested two SFAS 106 regulatory assets in its stranded cost quantification. The first SFAS 106 regulatory asset represents the unamortized balance of the 1993 and 1994 deferrals authorized in the settlement of the Docket No. R-00922479 proceeding. The Company computed the December 31, 1998 unamortized balance at $32.615 million.

The second SFAS 106 regulatory asset represents PECO's deferral in 1994 of the SFAS 106 previously unrecognized transition obligation associated with employees terminated under two early retirement programs (the VRIP and VSIP). As described in Mr. Cohn's direct testimony in this proceeding, PECO was required to write off the portion of the SFAS 106 transition obligation associated with these employees under generally accepted accounting principles. However, the Company determined that it could avoid the writeoff by recognizing a regulatory asset since the revenue stream, over the amortization period, was assumed equal to those expenses. The Company computed the December 31, 1998 unamortized balances at $67.965 million.

Q. **Is it appropriate to include the first SFAS 106 regulatory asset that represents the unamortized balance of the 1993 and 1994 deferrals in the stranded cost quantification?**

A. Conceptually, this SFAS 106 regulatory asset is appropriate to include in the stranded cost computation since it was the result of deferrals authorized by the Commission and agreed to by the parties in the settlement of that case. However, PECO's quantification of this SFAS 106 regulatory asset as a stranded cost is incorrect and overstated.

Q. **Why is the Company's quantification of this SFAS 106 regulatory asset incorrect and overstated for stranded cost quantification purposes?**

A. The Company's quantification is incorrect since it is stated on a nominal dollar basis, rather than on a net present value basis as required by the Competition statute.

Q. Have you quantified the net present value of the 1993 and 1994 SFAS 106 deferrals at December 31, 1996?

A. Yes. I have quantified the 1993 and 1994 SFAS 106 deferrals component of this regulatory asset as $20.394 million at December 31, 1998. I have assumed the same amortization period currently utilized by the Company for amortizing these deferred costs and the 7.60% discount rate discussed later in my testimony. The quantification is detailed on my Exhibit___(LK-5).

Q. Is it appropriate to include in the stranded cost quantification the SFAS 106 regulatory asset representing the unamortized balance of the 1994 writeoff associated with the VRIP and VSIP early retirement programs?

A. No. First, the Company had no authority from the Commission to defer the SFAS 106 previously unrecognized transition obligation associated with the early retirement programs. The Company was required under generally accepted accounting principles to write off this transition obligation, but for its unilateral recognition of the SFAS

106 deferred asset. To grant the Company recovery of this unilateral deferral would represent improper retroactive ratemaking.

Second, the Company has neglected to include in its filing as a regulatory liability the future revenue streams that it will collect from ratepayers under current base rates, under the assumption that it still incurred all the costs associated with the terminated VRIP and VSIP employees. Obviously, it no longer incurs those costs, yet the Company has not reduced its base revenues to reflect that fact. According to the 1995 PECO 10-K, the Company has identified $60 million in savings in 1995 and anticipates $100 million in savings annually thereafter. Thus, to be consistent, PECO should net the future revenue streams it alleges are due from ratepayers with those that represent its future overrecoveries (for expenses it no longer incurs) from ratepayers for the same events. The annual $100 million savings for the next ten years would represent a regulatory liability of $1.0 billion on a nominal basis.

Q. **Is it your recommendation that the Commission establish a $1.0 billion regulatory liability for the continuing overrecoveries due to the cost reductions associated with the 1994 VRIP and VSIP early retirement programs?**

A. No. However, my recommendation is contingent upon not including the 1994 VRIP and VSIP SFAS 106 deferrals as regulatory assets in the stranded cost quantification.

If the Commission does recognize the Company's SFAS 106 regulatory asset, then it also should recognize the regulatory liability associated with the continuing revenue overrecoveries.

Q. **Is there another issue associated with SFAS No. 106 that should be considered in the stranded cost quantification?**

A. Yes. Since 1995, the Company has been collecting $36.5 million in rates for SFAS 106 costs in excess of its cash payment requirements. The generation portion of the $36.5 million is $18.013 million based upon the 52.50% labor and 94.0% electric allocation factors utilized by Mr. Cohn for SFAS 106 costs on Exhibit ABC-1, Schedule 6 page 2 of 3. The Commission required the Company to place the accrued amounts in excess of cash payments into an external trust fund. The amounts in the trust fund have been earning a return that annually reduces the Company's SFAS 106 expense and which will continue to do so in the future by even greater amounts. The Company will have recovered $72.051 million by December 31, 1998 related to generation which will continue to grow as additional amounts are collected through base rates in excess of cash payments. In addition, the earnings on the trust funds will continue to grow.

Q. **Should the Commission recognize a regulatory liability for the SFAS 106 trust fund earnings?**

A. Yes. The present value of the earnings on the trust fund related to generation should be treated as a regulatory liability since it represents amounts recovered from ratepayers prior to the Company's requirement to pay these retiree costs. At some date in the future, the SFAS 106 costs will be less than the cash payments. However, the ratepayers will never reap the benefit of their overpayments since the generation function will be unbundled prior to this future crossover date. Since these are prepayments by ratepayers, ratepayers are entitled to a return on these amounts, consistent with the recognization of these trust fund earnings under traditional regulation.

Q. **Have you quantified the present value of the future SFAS 106 trust fund earnings related to generation?**

A. Yes. The regulatory liability is at least $150.861 million. I have assumed recoveries of SFAS 106 expenses in excess of cash payments for the next fourteen years, the residual of the transition obligation amortization period, followed by a ten year period over which the cumulative excess recoveries in the fund are paid out to retirees on an annual uniform basis. I have utilized the 7.5% return on trust fund assets assumed by PECO to compute the annual savings and discounted the earnings by the 7.60% after tax on capital. The computations are detailed on my Exhibit ____(LK-6).

Q. **What is the net quantification of your SFAS 106 recommendations?**

A. The net result is a regulatory liability with a net present value at December 31, 1998 of $130.467 million. That consists of a regulatory asset for the 1993-1994 deferrals quantified at $20.394 million, zero for the portion of the transition obligation related to the 1995 early retirement programs, and a regulatory liability of $150.861 million for the trust fund earnings.

VI. LIMERICK 1 AND 2 DECLARATORY ORDERS

Q. Please describe the Company's request for recovery of the costs deferred pursuant to the Limerick 1 and 2 declaratory orders.

A. The Company included unamortized balances of $18.301 million for Limerick 1 and $67.985 million for Limerick 2 as regulatory assets in its stranded cost quantification. The costs represent the unamortized balance at December 31, 1998 of post-commercial operating expenses incurred by PECO at the Limerick 1 and 2 units prior to the costs being recognized in rates. The costs were deferred as "early window" costs pursuant to Commission orders.

The Company was authorized by the Commission in Docket No. R-891364, on May 16, 1990, to amortize the Limerick 1 early window deferred operating expenses over a ten year period. Last year the Company was authorized by the Commission to amortize Limerick 2 early window deferred operating expenses over a nine year period commencing October 1, 1996. In neither instance was the Company granted a return on the unamortized balance.

In this filing, the Company has included the amortization of these costs on a straight line basis over a seven year period with no return on the unamortized balances. This had the effect of lengthening its amortization and recovery period compared to that which had been authorized previously by the Commission.

Q. **Did the Company properly compute its regulatory asset stranded cost claim for the Limerick 1 and 2 early window costs?**

A. No. PECO included these costs at December 31, 1998 on a nominal dollar basis. That is clearly contrary to the statute, as I have previously discussed, which requires that regulatory assets be stated on a net present value basis. Thus, the Company's quantification of these regulatory assets is overstated.

Q. **Have you performed a net present value quantification of these regulatory assets?**

A. Yes. The net present value quantifications at December 31, 1998 are $14.305 million for the Limerick 1 and $53.141 million for the Limerick 2 early window costs, respectively. To perform the net present value quantifications, I utilized the revised seven year amortization period reflected in the Company's filing and the after tax discount rate of 7.60%, which I subsequently discuss in my testimony. The computations are detailed on my Exhibit___(LK-7).

VII. NUCLEAR DESIGN BASIS DOCUMENTATION AND PEACH BOTTOM/LIMERICK WATER CHEMISTRY

Q. Please describe the Company's request for recovery of deferred nuclear design basis documentation and Peach Bottom/Limerick water chemistry costs.

A. The Company included a balance of $28.852 million for nuclear design basis documentation costs and $6.692 million for Peach Bottom/Limerick water chemistry costs. The Company has reflected a return on the nuclear design basis documentation costs (Exhibit ABC-1 Schedule 10 page 2 of 5) but not on the Peach Bottom/Limerick water chemistry costs (Exhibit ABC-1 Schedule 10 page 4 of 5).

The nuclear design basis documentation project was initiated in 1988 to develop a "single source map for all design-basis information," according to PECO witness Alan Cohn. The Company sought and obtained from the FERC authorization, for book accounting purposes, to defer the costs and to amortize the deferred costs to expense over the lives of the nuclear units. The amounts were deferred to account 182.2, "unrecovered plant costs and regulatory studies." In its filing in this proceeding, the Company included a return on the unamortized balance of these costs and shortened the amortization period to the seven year CTC recovery period.

The Peach Bottom/Limerick water chemistry system changes costs were initiated as a "potential solution" to the problem of intergranular stress corrosion cracking, according to PECO witness Alan Cohn. The projects at both nuclear facilities were started in the mid-1980s but discontinued due to unsatisfactory test results. Similar to the nuclear design basis documentation costs, PECO sought and obtained from the FERC authorization, for book accounting purposes, to defer the costs to account 182, "unrecovered plant and regulatory costs." Neither of the projects has been satisfactorily completed. In its filing in this proceeding, the Company has not included a return on the unamortized balance of these costs but has amortized the costs on a straight line basis over the seven year CTC recovery period.

Q. Why were these costs deferred for accounting purposes in account 182.2 and account 182?

A. PECO sought special dispensation from the FERC to avoid recognizing the costs to expense. In the absence of the FERC book accounting authorization, these costs were required to be expensed. The costs did not qualify for capitalization as construction work in progress or plant in service.

Q. Does the FERC authorization to defer these costs for book accounting purposes establish an entitlement to ratemaking recovery?

A. No. First, PECO neither sought nor obtained from this Commission an order authorizing the deferral of these costs for accounting or ratemaking purposes. Second, even if it had sought and obtained such an order, this Commission has demonstrated through orders in other proceedings that such an authorization does not create an entitlement to ratemaking recovery. A recent example is the disallowance of Pennsylvania Power & Light's Susquehanna 1 early window declaratory order cost deferrals in Docket No. R-943271. Third, the Company's request clearly represents an attempt at improper and single issue retroactive ratemaking recovery.

Q. Should the Commission recognize these costs as regulatory assets for stranded cost purposes?

A. No. These costs are disqualified for recovery as stranded costs since they do not meet the statutory requirement that they be properly recoverable under traditional regulation. The costs are not properly recoverable under traditional regulation for the same reasons that the deferral for book accounting purposes does not result in an entitlement to ratemaking recovery.

Q. Has the Company properly computed these deferred costs under the statutory requirements for quantifying regulatory assets?

A. No. However, this is only relevant if the Commission recognizes these costs as regulatory assets properly recoverable as stranded costs through the CTC. First, both the nuclear design basis documentation and the water chemistry system changes should be treated consistently and with no return on the unamortized balance. Thus, the nominal dollar balance of the nuclear design basis documentation deferred costs must be discounted based upon the future recovery period. Based upon the Company's proposed seven year amortization period, the nuclear design basis documentation deferred costs and the water chemistry system changes deferred costs stated at December 31, 1998 net present value amounts would be $22.552 million and $5.231 million, respectively. I utilized a 7.60% discount rate, which I subsequently discuss in my testimony. The computations are detailed on my Exhibit ____(LK-8).

Second, the seven year amortization period requested by the Company should be extended to the remaining lives of the nuclear units. There is no reason offered by the Company for the seven year period except that it corresponds to the seven year CTC recovery period. By contrast, the Company acknowledges that it sought authorization from FERC to amortize the nuclear design basis documentation costs and the water chemistry system changes over the remaining lives of the nuclear units since the "benefits will be realized over the lives of the plants."

Thus, if the Commission recognizes these costs as regulatory assets in the stranded cost quantification, the nuclear design basis documentation deferred costs and the water chemistry system changes deferred costs should be stated at the net present value amounts of $14.715 million and $3.413 million, respectively, at December 31, 1998. Similar to the net present value quantification for the seven year amortization period, I utilized a 7.60% discount rate. I utilized an average nuclear unit remaining life of 21 years. While PAIEUG opposes the inclusion of these costs as regulatory assets, a proper computation is detailed on my Exhibit ____(LK-9).

VIII. NUCLEAR DECOMMISSIONING

Q. Please describe the Company's request for recovery of nuclear decommissioning costs.

A. The Company's request for nuclear decommissioning costs consists of two components. The sum of the two components at December 31, 1998 represents the site specific estimate at December 31, 1996 prepared by PECO witness Thomas LaGuardia of TLG Services, Inc. based upon the complete demolition of all facilities and greenfield restoration of all sites grossed up for two years of inflation by PECO witness Alan Cohn.

The first of the two components is a claim for a nominal dollar amount of $236.929 million (Exhibit ABC-1 Schedule 10 page 4 of 5). That amount represents a prorata portion of the total LaGuardia/Cohn cost estimate at December 31, 1998 based upon the ratio of the years in service through that date to the total years useful life estimated for each nuclear generating unit, less the estimated trust fund balance at December 31, 1998.

The second of the two components is the present value of the ongoing future annual nuclear decommissioning expense accruals for the residual decommissioning cost not included in the first component. Thus, the future annual expense accruals resulted in lower market value and higher stranded generation costs quantified by PECO. PECO included the annual future accruals it projected would be necessary under the LaGuardia/Cohn estimate in the annual after tax contribution margin provided by sales at market. These annual future accruals were reflected in the market value and stranded generation cost quantifications contained in PECO Exhibits TPH-3, TPH-4, and TPH-5.

Q. **Has the Company properly computed its claim for the regulatory asset at December 31, 1998?**

A. No. The Company's approach is seriously flawed, resulting in a regulatory asset when there should be a regulatory liability. First, the Company failed to include earnings on the additional trust fund contributions to December 31, 1996 to compute the balance at December 31, 1998. Consequently, the balance at December 31, 1998 of trust fund assets should be higher by $2.918 million and the regulatory claimed asset reduced by the same amount.

Second, the Company's approach failed to recognize that earnings on the trust fund will continue to compound at the 7.5% assumed earnings rate, well in excess of the Company's assumed GDP escalation rate in the future decommissioning cost compared to the current cost. That differential, between the future value of the trust fund earnings and the future value of the decommissioning cost escalation, when discounted at the 7.60% after tax cost of capital, further reduces the Company's claimed regulatory asset on a net present value basis by $344.399 million.

Third, the Company's approach failed to consider earnings on the trust fund subsequent to the retirement of the nuclear generating units but prior to the actual disbursement from the fund for decommissioning. The post-retirement decommissioning periods for each of the nuclear generating units extend for more than ten years beyond their retirement dates, with most of the expenditures incurred over the initial six to eight years post-retirement. Consequently, additional earnings on the trust fund during this post-retirement period will reduce the regulatory asset even further. I quantified this additional reduction to the regulatory asset on a net present value basis as $32.940 million.

The computations underlying the quantification for each of these three PECO errors are detailed on my Exhibit ____(LK-10).

Q. **Is there an alternative manner of viewing your recommendations regarding PECO's claimed nuclear decommissioning regulatory asset in conjunction with its future annual nuclear decommissioning expense accruals?**

A. Yes. Both conceptually and computationally, the result would be the same if the regulatory asset/liability were to be established at zero, and the market value increased and the stranded generation costs concomitantly reduced by a net present value of $140.410 million. Because PECO failed to consider the future earnings on the existing trust fund balance after December 31, 1998, it overstated the future annual expense accruals on an annuity basis utilized in its market value quantifications.

If the annual expense accrual had been computed directly as the annuity required to attain the future value of the disbursements required, given the existing trust fund balance and PECO's assumptions regarding cost escalation and the rate of return on trust fund earnings, then the annual contribution margins in the PECO market value computations would have been higher. Thus, the net present value of the stranded generation costs would have been lower.

Q. What conclusion have you reached regarding the nuclear decommissioning regulatory asset claimed by PECO?

A. The nuclear decommissioning trust fund is <u>overfunded</u> based upon the current cost estimates, given PECO's assumptions regarding escalation in the cost estimate to future dollars, the rate of return on trust fund earnings, and the continued future annual expense accruals incorporated into PECO's market value quantification.

Q. What is your recommendation regarding the nuclear decommissioning regulatory asset claimed by PECO?

A. I recommend that the Commission recognize a regulatory liability of $140.410 million on a net present value revenue requirement basis at December 31, 1998.

Q. Does the failure of PECO to recognize earnings on the nuclear decommissioning trust funds post-retirement also impact PECO's quantifications of market value and stranded generation cost?

A. Yes. The future annual nuclear decommissioning expense accruals utilized by PECO to determine market value are also excessive and result in the understatement of market value. If earnings on the trust funds post-retirement are properly recognized, then the required future annual expense accruals will be lower.

Q. Have you quantified the effect on the future annual nuclear decommissioning accruals of the post-retirement earnings?

A. Yes. I have recomputed the future annual expense accruals. For simplicity, I simply added an additional three to four years to the decommissioning date, approximately midpoint of the disbursement pattern for most of the decommissioning expenditures (based on Mr. LaGuardia's study) in order to compute the future value and the levelized annual decommissioning expense accruals for each PECO nuclear generating unit. The computations are detailed on my Exhibit ____(LK-11).

Q. Please describe PECO's assumption regarding the taxability of earnings on future contributions to the nuclear decommissioning trust fund through the future annual accruals reflected in its market value quantifications.

A. The Company assumed that these earnings would be taxed at the full federal and state corporate tax rates rather than the special qualified trust fund income federal tax rate of 20% and state income tax rate of 2.8%. To incorporate this assumption, Mr. Cohn utilized a 6.5% trust fund earnings rate, rather than the 7.5% rate currently assumed and authorized by the Commission. However, this assumption on taxability is by no means certain, as acknowledged by Mr. Cohn in his testimony. Mr. Cohn also suggested that the potential for the application of the higher tax rates could be mitigated if the future annual accruals were recognized as a T&D wires charge.

Q. What is your recommendation on the taxability issue?

A. I recommend that the Commission assume continued tax deductibility and the current lower income tax rate for earnings on qualified trust funds. The Company's concern should not be elevated to certainty and incorporated in the quantifications of a lower market value and higher generation stranded cost. To the contrary, the trust fund after tax earnings rate assumption should be consistent with continuation of the status quo. If the potential tax issues become reality, PAIEUG believes PECO can petition the Commission for additional relief under § 2804(4)(iii) (c) or (f) of the Competition Act.

IX. FOSSIL DECOMMISSIONING

Q. Please describe the Company's request for recovery of fossil decommissioning costs.

A. The Company's request for fossil decommissioning costs consists of two components. The sum of the two components at December 31, 1998 represents the site specific estimates at December 31, 1996 prepared by PECO witness Thomas LaGuardia of TLG Services, Inc., which were grossed up for two years of inflation by PECO witness Alan Cohn. The estimates assume the complete demolition of all facilities and site restoration.

The first of the two components is a claim for a nominal dollar amount of $126.605 million (Exhibit ABC-1 Schedule 10 page 4 of 5). That amount represents a prorata portion of the total LaGuardia/Cohn cost estimate at December 31, 1998 based upon the ratio of the years in service through that date to the total years useful life estimated for each fossil generating unit.

The second of the two components is a net present value amount of $22.2 million (Cohn testimony page 20 lines 13-14) reflected in a lower market value and higher stranded generation cost as quantified by PECO. PECO included the annual future accruals it projected would be necessary under the LaGuardia/Cohn estimate in the annual after tax contribution margin provided by sales at market. These annual future accruals were reflected in the market value and stranded generation cost quantifications contained in PECO Exhibits TPH-3, TPH-4, and TPH-5.

Q. Are fossil decommissioning studies, such as the one performed by Mr. LaGuardia, objective studies of certain future costs?

A. No. To the contrary, fossil decommissioning studies are the result of assumptions premised upon assumptions. As such, they are inherently speculative and uncertain. One fundamental assumption underlying such studies, and upon which are premised other assumptions, is that the Company's generating facilities actually will be permanently retired, dismantled, and the sites restored while under the ownership and control of the utility. PECO has made no such commitments in this proceeding. Mr. LaGuardia simply has taken this assumption, along with others, to compute the "what-if" costs of decommissioning. The result is illusory at best.

A second fundamental assumption is that the Company's generating facilities actually will be retired at the dates indicated in the study. Historical experience throughout the utility industry has demonstrated that appropriate maintenance policies, capital expenditures for replacements and life extension, and repowering result in extended operating lives for generating facilities. In addition, PECO has made no commitments actually to retire its units on the study's assumed schedule in this proceeding. To the contrary, PECO has assumed in its market valuation studies that the Keystone 1 and 2 units and the Conemaugh 1 and 2 units will operate through 2018 and 2021, respectively, compared to the retirement dates assumed by Mr. LaGuardia of 2008 and 2011, respectively. Thus, despite the clear absurdity of the premature retirement assumptions for the Keystone and Conemaugh units, and the uncertainty of the retirement dates of the other units, Mr. LaGuardia simply has utilized these assumptions in order to compute the "what-if" costs of decommissioning, costs that are simply incorrect.

A third fundamental assumption is the projection of the costs necessary to fully dismantle the generating facilities and to restore the sites. It is clear that this is a matter of significant uncertainty, completely dependent upon numerous assumptions of the need for and extent of dismantling, along with the technology that will be available and the related individual costs projected ("guessed at") for decades into the future. To "address" the uncertainty in this third fundamental assumption, Mr. LaGuardia apparently felt compelled to add a series of "contingency" factors, aggregating some 13.6% over his base estimate ("guess"). Even casual observers would note that adding amounts to already uncertain amounts does nothing to decrease the inherent uncertainty, but rather does everything to increase the projected recovery amounts to even higher levels, the latter with certainty.

This fossil decommissioning request and the underlying study cannot be considered an objective and certain projection of future costs. Instead, it is highly speculative and uncertain by its very nature.

Q. **Has the Commission recognized the speculative and uncertain nature of projected fossil decommissioning costs in rejecting these costs in previous ratemaking proceedings?**

A. Yes. The Commission has consistently rejected projected fossil decommissioning costs based upon the argument that such costs are inherently speculative and uncertain. Thus, because the costs are not known and measurable, they are not recoverable. Fossil decommissioning costs have not been allowed by the Commission unless and until they are actually incurred, thereby meeting the known and measurable criterion.

In its Docket No. R-942986 Order dated December 29, 1994 (West Penn base ratemaking proceeding), the Commission articulated this argument very clearly as follows.

> **"Consequently, we reject the Company's claim because of its uncertain and speculative nature and because this claim is patently counter to existing precedent."** (slip op., page 63)

Q. Has the issue of ratemaking recovery of prospective decommissioning costs been addressed by the courts?

A. Yes. Although I am not offering a legal opinion, it is clear that the Commission has consistently relied upon the Penn-Sheraton court case in its ratemaking orders on the issue of projected fossil decommissioning costs. PECO witness Alan Cohn has acknowledged the Penn-Sheraton case "has generally been read as barring the prospective recovery of decommissioning costs by Pennsylvania utilities" (PECO Statement 3, page 18 lines 12-24). Thus, the Commission legally may be precluded from allowing recovery of projected fossil decommissioning costs.

The court in the Penn-Sheraton case stated the following.

> **"It is clear in our law that 'In no event will a utility be permitted to recover by annual allowances for depreciation a total amount in excess of the original cost, since annual depreciation is computed on original cost and not upon fair value or reproduction cost.'"**
>
> **". . . Negative salvage attributed to existing plant is purely prospective; it is a cost which has not yet been incurred; it is uncertain when and if it will be incurred; and it is not a part of the original cost of construction of the facilities when first devoted to public service. To permit the recovery of prospective negative salvage is to permit the recovery of a total amount in excess of the original cost of construction prior to the actual expenditure of those costs and, in our opinion, represents the recovery of something in the nature of a future reproduction cost. The established law in this Commonwealth does not permit the recovery by annual depreciation of any such prospective excess."**
> (198-A.2d pages 327-329)

Q. Even given that the projected costs of fossil decommissioning are not properly recoverable as a stranded cost, are there computational errors in the Company's quantification?

A. Yes. Although the list is not exhaustive, the Company's quantification is excessive and suffers from at least the following deficiencies.

- The first component is stated by PECO on a nominal dollar basis rather than a present value basis. As such, it fails to incorporate earnings on decommissioning collections in excess of the escalation to future values of the decommissioning cost estimate.

- The retirement dates utilized in the LaGuardia/Cohn study for the Keystone and Conemaugh units are earlier than the retirement dates utilized by PECO witness Mr. Hill in his market valuation studies.

- The future fossil decommissioning accruals computed by Mr. Cohn incorrectly assume that the decommissioning funds will be spent the same year as the unit is retired. Dismantling usually does not occur instantaneously and there would be additional earnings on the funds precollected from ratepayers.

Q. **What is your recommendation regarding PECO's claim for fossil decommissioning costs as stranded costs?**

A. I recommend that the Commission not allow this claim. PECO's claim fails to meet the statutory requirements for regulatory assets, although PECO was careful not to characterize its request for projected fossil decommissioning as a regulatory asset. Nevertheless, the projected costs are not known and measurable with even a modicum of certainty. Second, the costs would not be recoverable under traditional regulation unless and until actually incurred. Third, the Company's quantification is excessive and suffers from serious deficiencies.

Q. **How has PAIEUG reflected your recommendation in its quantification of stranded costs?**

A. I have reflected a zero quantification for the first component of projected fossil decommissioning costs on my summary table included in the Summary section of my testimony. PAIEUG witness Mr. Baron has utilized the zero amount for this first component in his quantification of the CTC revenue requirement.

In addition, PAIEUG witness Mr. Falkenberg has relied upon my recommendation and reflected no future annual fossil decommissioning cost accruals in his computations of market value and generation stranded costs.

X. OTHER TRANSITION COSTS

Q. Please describe the Company's request for recovery of other transition costs.

A. The Company included a balance of $32.661 million in other transition costs as a recoverable cost in its stranded cost quantification. The Company has requested recovery of two specific transition costs. The first is the cost of the proceedings and filings associated with implementation of the Competition Act. The second is the cost of customer education programs mandated by the Competition Act. In this filing, the Company has reflected these costs on an annual basis as $4.666 million over each of the seven years in the CTC recovery period. The Company has not reflected a return on the balance.

Q. Did the Company properly compute this balance of other transition costs for purposes of its stranded cost claim?

A. No. PECO included these costs December 31, 1998 on a nominal dollar basis. To comply with the Competition Act and to be consistent with the net present value quantification of the regulatory assets, other transition costs should also be quantified on a net present value basis.

Q. Have you performed a net present value quantification of these regulatory assets?

A. Yes. The net present value quantification at December 31, 1998 is $25.530 million. To perform the net present value quantification, I utilized the after tax discount rate of 7.60%, which I subsequently discuss in my testimony, applied to the annual cost streams over the seven year period. The computations are detailed on my Exhibit___(LK-12).

XI. DISCOUNT RATES

Q. Please describe the two discount rates employed by the Company.

A. The Company developed and employed two discount rates. The first one, at 8.41%, was utilized for discounting the after tax contribution margins to determine market value in the generation stranded cost computation. That discount rate was based upon the Company's cost of long term capital at year end 1996 and was sponsored by PECO witness Joseph Brennan. Details of his computations are reflected on his Exhibit JFBr-1 Schedule 1, which I have replicated as my Exhibit___(LK-13).

The second one, at 8.02%, was utilized for computing the levelized annual revenue requirement for the CTC as discussed by PECO witness Alan Cohn on pages 52-53 of his testimony and reflected on his Exhibit ABC-1 Schedule 1 page 1 of 5. That discount rate was based upon the Company's cost of long term capital at year end 1996, adjusted to remove the effects of the deferred loss on reacquired debt. The Company has separately treated the generation portion of the effects of the deferred loss on reacquired debt as a regulatory asset in its filing.

Q. Did the cost of capital computed by PECO affect any other computations in the determination of its stranded cost claim?

A. Yes. Mr. Cohn utilized the grossed up return of 13.71%, which is the 8.02% after tax discount rate he utilized to levelize the CTC revenue requirement grossed up for federal and state income taxes, to determine the annual CTC revenue requirements on his Exhibit ABC-1 Schedule 10 page 2 of 5.

Q. What rate of return on common equity was embedded in the two discount rates employed by the Company?

A. The Company utilized a return on common equity of 11.6%, which was sponsored by PECO witness Joseph Brennan.

Q. How was the return on common equity computed by PECO?

A. PECO took the simple average of four separate computations. Two computations were made by Mr. Brennan utilizing the DCF methodology. The first DCF computation was for PECO Energy Company. The second DCF computation was for a "barometer group" of nine electric utilities. The DCF methodologies yielded a return on common equity of 10.9% for PECO Energy Company and 10.8% for the barometer group.

Two additional computations were made by Mr. Brennan utilizing the CAPM methodology. The first CAPM computation was for PECO Energy Company. The second CAPM computation was for the "barometer group" of nine electric utilities. The CAPM methodologies yielded a return on common equity of 12.2% for PECO Energy Company and 11.8% for the barometer group.

A summary of Mr. Brennan's computations underlying the 11.6% return on common equity utilized by PECO for all discount rate and return purposes is reflected on Mr. Brennan's Exhibit JFBr-1 Schedule 2, which I have replicated as my Exhibit___(LK-14) for convenience.

Q. **Has the Commission utilized the CAPM methodology in other recent electric rate proceedings to determine the required return on common equity?**

A. No. The Commission has repeatedly rejected the CAPM methodology, instead relying primarily on the DCF methodology. Recent proceedings in which the Commission rejected the use of the CAPM methodology include the PECO QRO proceeding and the last base rate proceedings for Pennsylvania Power & Light ("PP&L") and West Penn Power Company ("West Penn").

In its Docket No. R-973877 Order dated May 22, 1997 (PECO QRO proceeding), the Commission responded to PECO's exceptions to the Commission's rejection of the CAPM and risk premium ("RPM") methodologies sponsored by PECO and stated the following.

> **"In considering this matter, we note that, in numerous recent proceedings, we have determined a utility's cost of common equity using primarily the DCF (Discounted Cash Flow) method and informed judgment. . . Therefore, we reject PECO's argument that the OTS' reliance solely on the DCF methodology is improper in this proceeding."** (pages 57-58).

In its Docket No. R-943271 Order dated September 21, 1995 (PP&L base ratemaking proceeding), the Commission rejected the CAPM and RPM methodologies sponsored by PP&L and stated the following.

> **"First, we cannot accept that historic experienced earnings reflect the cost of capital. We know of no reputable analyst who would seriously argue that experienced earnings represent the cost of capital, except by pure happenstance. But, such is the inherent assumption of each methodology [CAPM and RPM]. Second, we cannot accept, even assuming that historic experienced earnings represent the cost of capital, that the <u>average</u> premium of an equity investment over a fixed income period as long as fifty years, represents the investor required premium in today's and tomorrow's market.**
>
> **Accordingly, we conclude that we can place little credence in the results of these methodologies."** (slip op., page 161)

The Commission concluded later in that same order the following.

> **"On the basis of the record before us herein, we conclude that there is no reason for us to divert from our practice of considering the DCF method exclusively for equity rate of return determinations. Accordingly, PP&L's Exceptions regarding this issue are denied."** (slip op., page 184).

In its Docket No. R-942986 Order dated December 29, 1994 (West Penn base ratemaking proceeding), the Commission rejected the CAPM and RPM methodologies sponsored by West Penn and stated the following.

> **"On consideration of the record herein, we conclude that the proper range of return on common equity should be based upon the standard DCF methodology . . . "** (slip op., page 94-95)

Thus, it would be inappropriate and inconsistent with "traditional regulation" for the Commission to utilize the CAPM methodology to determine the required return on common equity, even as a component of an average as proposed by PECO in this proceeding.

Q. **What rate of return on common equity did the Commission authorize in the PECO QRO proceeding?**

A. The Commission determined that the required return on common equity was 10.0% based upon the DCF methodology.

Q. What is your recommendation on the return on common equity that should be utilized for discount rate and CTC revenue requirement purposes?

A. I recommend that the Commission utilize the 10.0% return on common equity based on the DCF methodology ordered in the PECO QRO proceeding. That rate of return is not only the most recently adjudicated return on common, it is also still current and need not be revisited.

Q. Please describe the computations of the discount rates and the CTC revenue requirement rate of return utilized by the PAIEUG witnesses.

A. I have developed two discount rates, the first based upon PECO's cost of capital without removal of the unamortized debt reacquisition costs, and the second with the removal of the unamortized debt reacquisition costs, consistent with the use of two similar discount rates by PECO. The two different discount rates were necessary due to PECO's treatment of the unamortized debt reacquisition costs as a regulatory asset.

The first PAIEUG discount rate is 7.60%. That discount rate was utilized by PAIEUG witness Mr. Falkenberg in the market value and stranded generation cost quantifications. I have also utilized this discount rate to compute the net present value of regulatory assets and other transition costs at December 31, 1998. To compute this first discount rate, I utilized the capital structure and component costs sponsored by PECO witness Mr. Brennan on his Exhibit JFBr-1 Schedule 1, except for the return on common equity. I utilized the 10.0% return on common equity authorized by the Commission in the PECO QRO proceeding. The computations are summarized in the following table.

	% of Capital	Cost	Weighted Cost	After Tax Wtd Cost
Long Term Debt	43.10%	8.47%	3.65%	2.14%
MIPS Debt	3.30%	9.21%	0.30%	0.18%
Preferred Equity	3.00%	7.70%	0.23%	0.23%
Common Equity	50.60%	10.00%	5.06%	5.06%
Total	100.00%		9.25%	7.60%

The second PAIEUG discount rate is 7.23% and the CTC revenue requirement return is 12.35%, the latter rate computed by grossing-up the 7.23% after tax rate for federal and state income taxes. That discount rate and CTC revenue requirement rate of return were utilized by PAIEUG witness Mr. Baron for the CTC revenue requirement computations. I utilized the capital structure and component costs sponsored by

PECO witness Mr. Cohn, except for the return on common equity, which was provided in response to OCA-III-17 and which I have replicated as my Exhibit___(LK-15). I utilized the 10.0% return on common equity authorized by the Commission in the PECO QRO proceeding. The computations are summarized in the following table.

	% of Capital	Cost	Weighted Cost	After Tax Wtd Cost	Grossed Up Return
Long Term Debt	44.60%	7.47%	3.33%	1.95%	
MIPS Debt	3.20%	9.21%	0.29%	0.17%	
Preferred Equity	3.10%	6.37%	0.20%	0.20%	
Common Equity	49.10%	10.00%	4.91%	4.91%	
Total	100.00%		8.73%	7.23%	12.35%

Q. Are there any other issues that affect the computation of the discount rates and the CTC revenue requirement rate of return?

A. Yes. The most significant other issue affecting these rates is the composition of the capital structure. The Company, through its witness Mr. Brennan, has utilized a capital structure consisting only of long term debt, preferred equity, and common equity. However, the Company has outstanding a $425 million credit facility that it fully utilizes on an ongoing basis to finance its accounts receivables and certain regulatory assets. The average interest rate on this debt is 5.45%, according to the Company's response to PAIEUG V-19(b). Thus, this credit facility is a form of debt financing that could be considered by the Commission as appropriate to reflect in the computation of the discount rates and the CTC revenue requirement rate of return.

Q. **Has the Commission previously addressed the issue of whether the credit facility should be included in the capital structure for discount rate or return purposes?**

A. No. The Company initiated this form of financing subsequent to the Docket No. R-891364 proceeding, the Company's last base rate case, and the issue was not raised in the PECO QRO proceeding.

Q. **Why has PAIEUG not incorporated the credit facility debt financing into the discount rates and CTC revenue requirement rate of return it utilized in this proceeding?**

A. Although PAIEUG believes it is appropriate to include the credit facility debt financing in the capital structure and costs, it has exercised an abundance of caution to focus on issues with greater impact on the CTC computation.

Q. **If the Commission agrees that it is appropriate to include the $425 million credit facility in the capital structure, what impact would that have on the two discount rates and the CTC revenue requirement return?**

A. The discount rate for purposes of the market value and stranded generation cost computations would be 7.41%, computed as follows.

	Capital ($ million)	% of Capital	Cost	Weighted Cost	After Tax Wtd Cost
Long Term Debt	$3,953	41.19%	8.47%	3.49%	2.04%
MIPS Debt	$302	3.15%	9.21%	0.29%	0.17%
Credit Facility	$425	4.43%	5.45%	0.24%	0.14%
Preferred Equity	$272	2.83%	7.70%	0.22%	0.22%
Common Equity	$4,646	48.41%	10.00%	4.84%	4.84%
Total	$9,598	100.00%		9.08%	7.41%

The discount rate and CTC revenue requirement rate of return for purposes of the CTC revenue requirement computation would be 7.06% and 12.06%, respectively, computed as follows.

	Capital ($ million)	% of Capital	Cost	Weighted Cost	After Tax Wtd Cost	Grossed Up Return
Long Term Debt	$4,218	42.68%	7.47%	3.19%	1.87%	
MIPS Debt	$302	3.06%	9.21%	0.28%	0.16%	
Credit Facility	$425	4.30%	5.45%	0.23%	0.14%	
Preferred Equity	$292	2.95%	6.37%	0.19%	0.19%	
Common Equity	$4,646	47.01%	10.00%	4.70%	4.70%	
Total	$9,883	100.00%		8.59%	7.06%	12.06%

Q. What would be the impact on the stranded cost quantification of the parties?

A. The use of these discount rates and the related CTC revenue requirement rate of return would reduce the PAIEUG stranded generation cost quantification and increase the stranded regulatory asset quantification, if all other aspects of the computations remained unchanged.

Although PAIEUG has not included the quantification in its witness' testimonies, the effect on its recommendations can be computed by replacing the discount rates and the related CTC revenue requirement rate of return in the stranded cost quantification models utilized by the PAIEUG witnesses.

Likewise, the impact on other parties' stranded cost quantifications, including PECO's, can be computed by replacing the discount rates and the related CTC revenue requirement rate of return in the various stranded cost quantification models utilized by the various parties' witnesses.

Q. Does this complete your testimony?

A. Yes.

PAIEUG STATEMENT NO. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
V.	)	DOCKET NO. R-00973953
PECO ENERGY COMPANY	)	
APPLICATION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	)	

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

JUNE 1997

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Certified Management Accountants

Institute of Management Accountants

Seventeen years utility industry experience in the financial, rate, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **Kennedy and Associates:** Vice President and Principal. Responsible for utility revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Minnesota, North Carolina, Ohio, Pennsylvania, Texas, and West Virginia Public Service Commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

- Rate phase-ins.
- Construction project cancellations and write-offs.
- Construction project delays.
- Capacity swaps.
- Financing alternatives.
- Competitive pricing for off-system sales.
- Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Consumers
Leheigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
As of June 1997**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim 19th Judicial District Ct.	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebut	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebut	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.

Expert Testimony Appearances
of
Lane Kollen
As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.

**Expert Testimony Appearances
of
Lane Kollen
As of June 1997**

Date	Case	Jurisdict.	Party	Utility	Subject
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.

**Expert Testimony Appearances
of
Lane Kollen
As of June 1997**

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

**Expert Testimony Appearances
of
Lane Kollen
As of June 1997**

Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.

Expert Testimony Appearances of Lane Kollen As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.

Expert Testimony Appearances
of
Lane Kollen
As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

Expert Testimony Appearances of Lane Kollen As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Division	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, base revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.

Exhibit ____(LK-2)

FAS 109-Generation Only
PECO A/C 282 Electric
Computation and Gross-Up

Basis	Plant Temp Diff	Federal Tax Effect	State Tax Effect	Total Tax Effect
Unrecovered Plant Cost per Books	7,643,512,912			
Add: Unamortized ITC Balance	(294,830,132)			
Subtotal	7,348,682,780			
Less: Unrecovered Plant Cost Tax	1,721,242,718			
Basis				
Subtotal	5,627,440,062			
Plus: Transferred In				
A/C 186	(16,609,694)			
A/C 190	(158,968,822)			
A/C 281	(547,722)			
A/C 283	59,565,240			
Subtotal	5,510,879,064			
Less: non-operating Deferred Tax				
Expense	(61,570,656)			
Plant Related Temporary Difference	5,449,308,408			
Effective Income Tax Rate		0.35	0.063329	
Deferred Tax Computed		1,907,257,943	345,099,252	
Less: Book Deferred Income Tax		(1,117,341,682)	(1,223,988)	
Unbooked Deferred Income Tax		789,916,261	343,875,264	1,133,791,525
Federal Gross-up .35/1-.413329		676,404,720		
State Gross-up .063329/1-.413329			122,388,670	
Total Unbooked and Gross-up		1,466,320,981	466,263,934	1,932,584,916
A/C 282 Journal Entry				
Regulatory Asset	1,932,584,916			
Deferred Federal Income Taxes		1,466,320,981		
Deferred State Income Taxes		466,263,934		
Total	1,932,584,916	1,932,584,916		

	ACCT	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
VOLUNTARY EARLY RETIREMENT COSTS													
BEGINNING OF YEAR	18238		32,551	23,871	15,190	6,510							
ADDITIONS			0	0	0	0							
AMORTIZATION			-8,680	-8,680	-8,680	-6,510							
END OF YEAR		49,245	23,871	15,190	6,510	0							
GEN ALLOCATION 66.1%		32,551											
EMPLOYEE TRANSITION COSTS													
BEGINNING OF YEAR			0	5,014	10,793	12,591	12,518	12,916	8,258	4,605	2,308	842	
ADDITIONS			5,014	6,782	4,157	3,118	4,211						
AMORTIZATION				-1,003	-2,359	-3,191	-3,814	-4,658	-3,653	-2,297	-1,466	-842	
END OF YEAR		0	5,014	10,793	12,591	12,518	12,916	8,258	4,605	2,308	842	-0	
GEN ALLOCATION 66.1%													
1994 RATE CASE EXPENSES													
BEGINNING OF YEAR	18239		678	431	184								
ADDITIONS			0	0	0								
AMORTIZATION			-247	-247	-184								
END OF YEAR		1,025	431	184	-0								
GEN ALLOCATION 66.1%		678											
TAXES RECOVERABLE													
BEGINNING OF YEAR	18231		813,070	786,214	755,805	740,706	725,066	709,668	696,571	682,350	667,039	650,243	631,169
ADDITIONS			0	0	0								
TOTAL AMORTIZATION			-26,856	-30,409	-15,099	-15,640	-15,398	-13,097	-14,221	-15,311	-16,796	-19,074	-22,170
AMORTIZATION PUC JURISDICATION - Nuclear			-17,487	-20,333	-10,352	-10,985	-11,328	-9,919	-10,771	-11,596	-12,721	-14,446	-16,791
AMORTIZATION PUC JURISDICTION-Other Prod			-5,106	-6,004	-3,056	-3,225	-3,199	-2,728	-2,962	-3,169	-3,496	-3,973	-4,818
END OF YEAR- GENERATION		813,070	786,214	755,805	740,706	725,066	709,668	696,571	682,350	667,039	650,243	631,169	608,999
REG LIABILITIES (INVEST TAX CREDIT)													
BEGINNING OF YEAR	25405		-113,591	-109,534	-105,477	-101,421	-97,364	-93,307	-89,250	-85,193	-81,136	-77,080	-73,023
ADDITIONS													
AMORTIZATION			4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057
AMORTIZATION PUC JURISDICATION - Nuclear			2,433	2,512	2,576	2,639	2,764	2,845	2,845	2,845	2,845	2,845	2,845
AMORTIZATION PUC JURISDICTION-Other Prod			979	1,017	1,043	1,062	1,070	1,073	1,073	1,073	1,073	1,073	1,073
END OF YEAR- GENERATION		-113,591	-109,534	-105,477	-101,421	-97,364	-93,307	-89,250	-85,193	-81,136	-77,080	-73,023	-68,966
TOTAL BEGINNING OF YEAR BALANCE			858,532	848,014	842,633	721,897	697,389	680,102	660,064	639,904	620,010	599,465	579,098
ADDITIONS			49,538	53,079	4,157	3,118	4,211	0	0	0	0	0	0
AMORTIZATION-PUC JURISDICTION			-50,919	-52,473	-122,081	-26,261	-20,676	-19,630	-19,713	-19,409	-20,009	-19,764	-21,372
AMORTIZATION-TOTAL			-58,029	-58,434	-124,865	-27,599	-21,471	-20,012	-20,133	-19,866	-20,518	-20,340	-22,046
TOTAL END OF YEAR BALANCE		858,532	848,041	842,660	721,924	697,416	680,129	660,091	639,931	620,037	599,492	579,125	557,052

Exhibit ___(LK-3)
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	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
VOLUNTARY EARLY RETIREMENT COSTS													
BEGINNING OF YEAR													
ADDITIONS													
AMORTIZATION													
END OF YEAR													
GEN ALLOCATION 66.1%													
EMPLOYEE TRANSITION COSTS													
BEGINNING OF YEAR													
ADDITIONS													
AMORTIZATION													
END OF YEAR													
GEN ALLOCATION 66.1%													
1994 RATE CASE EXPENSES													
BEGINNING OF YEAR													
ADDITIONS													
AMORTIZATION													
END OF YEAR													
GEN ALLOCATION 66.1%													
TAXES RECOVERABLE													
BEGINNING OF YEAR	608,999	583,570	547,968	488,450	455,167	418,324	377,506	323,080	270,042	236,020	191,723	169,876	134,385
ADDITIONS													
TOTAL AMORTIZATION	-25,429	-35,602	-59,518	-33,283	-36,843	-40,818	-54,426	-53,038	-34,022	-44,297	-31,847	-25,491	-14,260
AMORTIZATION PUC JURISDICATION - Nuclear	-19,259	-28,964	-45,077	-25,207	-27,904	-30,914	-41,221	-40,169	-26,767	-33,549	-24,120	-19,306	-10,800
AMORTIZATION PUC JURISDICTION-Other Prod	-5,297	-7,416	-12,397	-8,933	-7,674	-8,502	-11,337	-11,047	-7,087	-9,227	-8,633	-6,310	-2,970
END OF YEAR- GENERATION	583,570	547,968	488,450	455,167	418,324	377,506	323,080	270,042	236,020	191,723	169,876	134,385	120,126
REG LIABILITIES (INVEST TAX CREDIT)													
BEGINNING OF YEAR	-68,966	-64,909	-60,852	-56,795	-52,739	-48,682	-44,625	-40,568	-36,511	-32,455	-28,398	-24,341	-20,284
ADDITIONS													
AMORTIZATION	4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057	4,057
AMORTIZATION PUC JURISDICATION - Nuclear	2,845	2,845	2,845	2,845	2,845	2,845	2,845	2,846	2,845	2,845	2,846	2,845	2,846
AMORTIZATION PUC JURISDICTION-Other Prod	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073
END OF YEAR- GENERATION	-64,909	-60,852	-56,795	-52,739	-48,682	-44,625	-40,568	-36,511	-32,455	-28,398	-24,341	-20,284	-16,227
TOTAL BEGINNING OF YEAR BALANCE	557,025	533,905	500,613	443,405	412,458	377,952	340,452	289,395	239,725	209,072	168,143	139,665	117,642
ADDITIONS	0	0	0	0	0	0	0	0	0	0	0	0	0
AMORTIZATION-PUC JURISDICTION	-22,384	-32,208	-55,303	-29,942	-33,379	-36,236	-49,327	-47,987	-29,624	-39,646	-27,623	-21,366	-10,640
AMORTIZATION-TOTAL	-23,092	-33,265	-57,161	-30,946	-34,506	-37,499	-51,057	-49,669	-30,653	-40,928	-28,478	-22,122	-10,891
TOTAL END OF YEAR BALANCE	533,932	500,640	443,432	412,458	377,952	340,453	289,398	239,726	209,072	168,143	139,[illegible]	117,642	106,[illegible]

Exhibit ___ (LK-3)
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	2021	2022	2023	2024
VOLUNTARY EARLY RETIREMENT COSTS				
BEGINNING OF YEAR				
ADDITIONS				
AMORTIZATION				
END OF YEAR				
GEN ALLOCATION 66.1%				
EMPLOYEE TRANSITION COSTS				
BEGINNING OF YEAR				
ADDITIONS				
AMORTIZATION				
END OF YEAR				
GEN ALLOCATION 66.1%				
1994 RATE CASE EXPENSES				
BEGINNING OF YEAR				
ADDITIONS				
AMORTIZATION				
END OF YEAR				
GEN ALLOCATION 66.1%				
TAXES RECOVERABLE				
BEGINNING OF YEAR	120,125	115,129	62,381	59,739
ADDITIONS				
TOTAL AMORTIZATION	-4,996	-52,768	-2,622	-59,739
AMORTIZATION PUC JURISDICATION - Nuclear	-3,784	-39,865	-1,986	-46,244
AMORTIZATION PUC JURISDICTION-Other Prod	-1,041	-10,891	-546	-12,443
END OF YEAR- GENERATION	115,129	62,381	59,739	0
REG LIABILITIES (INVEST TAX CREDIT)				
BEGINNING OF YEAR	-16,227	-12,170	-8,114	-4,057
ADDITIONS				
AMORTIZATION	4,057	4,057	4,057	4,057
AMORTIZATION PUC JURISDICATION - Nuclear	2,845	2,845	2,845	2,845
AMORTIZATION PUC JURISDICTION-Other Prod	1,073	1,073	1,073	1,073
END OF YEAR- GENERATION	-12,170	-8,114	-4,057	0
TOTAL BEGINNING OF YEAR BALANCE	106,651	105,023	55,624	56,370
ADDITIONS	0	0	0	0
AMORTIZATION-PUC JURISDICTION	-1,594	-47,726	698	-54,457
AMORTIZATION-TOTAL	-1,627	-49,399	747	-56,370
TOTAL END OF YEAR BALANCE	105,023	55,624	56,370	0

AMORTIZATION OF EMPLOYEE TRANSITION COSTS

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
-1,003	-1,003	-1,003	-1,003	-1,003								
	-1,356	-1,356	-1,356	-1,356	-1,366							
		-831	-831	-831	-831	-831						
			-624	-624	-624	-624	-624					
				-842	-842	-842	-842	-842				
-1,003	-2,359	-3,191	-3,814	-4,656	-3,653	-2,297	-1,466	-842				

Exhibit ___ (LK-3)
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Exhibit ____(LK-4)

PECO RESTRUCTURING
SFAS 109 @ 12/31/98
($000)

Discount Rate:	7.60%
Nominal Value 12/31/98:	1,687,069
Amortization Period:	26.9

Year	Nominal	Present Value
1999	62,716	60,420
2000	62,716	56,153
2001	62,716	52,187
2002	62,716	48,501
2003	62,716	45,075
2004	62,716	41,891
2005	62,716	38,932
2006	62,716	36,182
2007	62,716	33,627
2008	62,716	31,252
2009	62,716	29,044
2010	62,716	26,993
2011	62,716	25,086
2012	62,716	23,314
2013	62,716	21,668
2014	62,716	20,137
2015	62,716	18,715
2016	62,716	17,393
2017	62,716	16,165
2018	62,716	15,023
2019	62,716	13,962
2020	62,716	12,976
2021	62,716	12,059
2022	62,716	11,207
2023	62,716	10,416
2024	62,716	9,680
2025	56,445	8,097
2026		0
TOTAL	**1,687,069**	**736,153**

Exhibit ____(LK-5)

PECO Energy Company
SFAS No. 106 Regulatory Assets
1993 and 1994 Deferrals
Present Value of Amortization
(Amounts in $000)

	Annual Amortization	Present Value
1999	2,330	2,246
2000	2,330	2,087
2001	2,330	1,940
2002	2,330	1,803
2003	2,330	1,675
2004	2,330	1,557
2005	2,330	1,447
2006	2,330	1,345
2007	2,330	1,250
2008	2,330	1,162
2009	2,330	1,080
2010	2,330	1,003
2011	2,330	932
2012	2,330	867
Total	32,615	20,394

Exhibit ____(LK-6)

PECO Energy Company
SFAS No. 106 Regulatory Assets
Present Value of Earnings on Trust Fund
($000)

	Beginning Balance	Change	Ending Balance	Avg Balance Earnings	Present Value 12/31/98
1999	72,051	18,013	90,064	6,079	5,861
2000	90,064	18,013	108,077	7,430	6,657
2001	108,077	18,013	126,089	8,781	7,312
2002	126,089	18,013	144,102	10,132	7,841
2003	144,102	18,013	162,115	11,483	8,259
2004	162,115	18,013	180,128	12,834	8,578
2005	180,128	18,013	198,140	14,185	8,812
2006	198,140	18,013	216,153	15,536	8,969
2007	216,153	18,013	234,166	16,887	9,060
2008	234,166	18,013	252,179	18,238	9,094
2009	252,179	18,013	270,191	19,589	9,078
2010	270,191	18,013	288,204	20,940	9,018
2011	288,204	18,013	306,217	22,291	8,922
2012	306,217	18,013	324,230	23,642	8,795
2013	324,230	(32,423)	291,807	23,101	7,987
2014	291,807	(32,423)	259,384	20,670	6,641
2015	259,384	(32,423)	226,961	18,238	5,446
2016	226,961	(32,423)	194,538	15,806	4,386
2017	194,538	(32,423)	162,115	13,374	3,449
2018	162,115	(32,423)	129,692	10,943	2,623
2019	129,692	(32,423)	97,269	8,511	1,896
2020	97,269	(32,423)	64,846	6,079	1,259
2021	64,846	(32,423)	32,423	3,648	702
2022	32,423	(32,423)	(0)	1,216	217
Total					150,861

PECO RESTRUCTURING
LIMERICK 1 DECLARATORY ORDER @ 12/31/98
($000)

Discount Rate:	7.60%
Nominal Value 12/31/98:	18,301
Amortization Period:	7

Year	Nominal	Present Value
1999	2,614	2,519
2000	2,614	2,341
2001	2,614	2,175
2002	2,614	2,022
2003	2,614	1,879
2004	2,614	1,746
2005	2,614	1,623
2006		0
TOTAL	18,301	14,305

PECO RESTRUCTURING
LIMERICK 2 DECLARATORY ORDER @ 12/31/98
($000)

Discount Rate:	7.60%
Nominal Value 12/31/98:	67,985
Amortization Period:	7

Year	Nominal	Present Value
1999	9,712	9,357
2000	9,712	8,696
2001	9,712	8,082
2002	9,712	7,511
2003	9,712	6,980
2004	9,712	6,487
2005	9,712	6,029
2006		0
TOTAL	**67,985**	**53,141**

PECO RESTRUCTURING
NUCLEAR DESIGN BASIS DOC. @ 12/31/98
($000)

Discount Rate: 7.60%
Nominal Value 12/31/98: 28,852
Amortization Period: 7

Year	Nominal	Present Value
1999	4,122	3,971
2000	4,122	3,690
2001	4,122	3,430
2002	4,122	3,187
2003	4,122	2,962
2004	4,122	2,753
2005	4,122	2,559
2006		0
TOTAL	28,852	22,552

PECO RESTRUCTURING
WATER CHEMISTRY SYSTEM CHANGES @ 12/31/98
($000)

Discount Rate:	7.60%
Nominal Value 12/31/98:	6,692
Amortization Period:	7

Year	Nominal	Present Value
1999	956	921
2000	956	856
2001	956	795
2002	956	739
2003	956	687
2004	956	639
2005	956	593
2006		0
TOTAL	6,692	5,231

PECO RESTRUCTURING
NUCLEAR DESIGN BASIS DOC. @ 12/31/98
($000)

Discount Rate:	7.60%
Nominal Value 12/31/98:	28,852
Amortization Period:	21

Year	Nominal	Present Value
1999	1,374	1,324
2000	1,374	1,230
2001	1,374	1,143
2002	1,374	1,062
2003	1,374	987
2004	1,374	918
2005	1,374	853
2006	1,374	793
2007	1,374	737
2008	1,374	685
2009	1,374	636
2010	1,374	591
2011	1,374	550
2012	1,374	511
2013	1,374	475
2014	1,374	441
2015	1,374	410
2016	1,374	381
2017	1,374	354
2018	1,374	329
2019	1,374	306
2020		0
TOTAL	28,852	14,715

PECO RESTRUCTURING
WATER CHEMISTRY SYSTEM CHANGES @ 12/31/98
($000)

Discount Rate:	7.60%
Nominal Value 12/31/98:	6,692
Amortization Period:	21

Year	Nominal	Present Value
1999	319	307
2000	319	285
2001	319	265
2002	319	246
2003	319	229
2004	319	213
2005	319	198
2006	319	184
2007	319	171
2008	319	159
2009	319	148
2010	319	137
2011	319	127
2012	319	118
2013	319	110
2014	319	102
2015	319	95
2016	319	88
2017	319	82
2018	319	76
2019	319	71
2020		0
TOTAL	6,692	3,413

PECO RESTRUCTURING
NUCLEAR DECOMMISSIONING @ 12/31/98
($000)

	Prorated Fund Required @12/31/98	Est. Fund Balance @12/31/98	Est. Fund Deficiency @12/31/98	Retirement Date	Prorated Fund Required @Retire	Est. Fund Balance @Retire	Excess Fund Bal. @Retire	NPV Excess Fund Bal. @12/31/98	Midpt. Post-Retire Disburse.	Prorated Fund Required @Disb.	Est. Fund Balance @Disb.	Excess Fund Bal. @Disb.	NPV Excess Fund Bal. @12/31/98
Limerick 1	120,396	92,383	(28,013)	Oct 2024	288,230	789,282	501,052	77,335	2027	321,980	980,522	658,542	81,591
Limerick 2	103,773	54,362	(49,411)	Jun 2029	298,787	976,668	677,881	72,542	2033	346,323	1,304,309	957,986	76,479
Salem 1	77,604	44,570	(33,034)	Aug 2016	138,524	285,257	146,733	40,693	2020	160,284	380,952	220,668	45,654
Salem 2	64,666	38,557	(26,109)	Apr 2020	133,562	317,440	183,878	38,043	2024	154,811	423,932	269,120	41,538
Peach Bottom 1	36,124	8,830	(27,294)	Jul 2014	60,096	114,903	54,807	17,598	2016	64,482	132,785	68,303	18,942
Peach Bottom 2	87,950	58,625	(29,325)	Aug 2013	141,380	260,233	118,853	41,062	2017	162,738	347,533	184,795	47,629
Peach Bottom 3	117,267	58,667	(58,600)	Jul 2014	195,086	373,002	177,916	57,126	2018	224,666	498,133	273,467	65,505
Total			(251,786)										
Less Accumulated Def Inc Taxes			17,775										
Net Deficiency			(234,011)					344,399					377,339
Less PECO Claimed Deficiency			(236,929)										
Incremental Reduction In Regulatory Asset			2,918					344,399					32,940

Exhibit ___ (LK-10)

PECO RESTRUCTURING
FUTURE ANNUAL NUCLEAR DECOMMISSIONING
EXPENSE ACCRUALS

Unit	Decom. Cost in 1998 $	Decom. Cost in Future Yr $	Midpoint Disbursement	Annual Exp. @ 7.5%
Peach Bottom 1	24,082,979	42,987,116	2016	1,204,884
Peach Bottom 2	58,393,296	108,044,406	2017	2,745,506
Peach Bottom 3	78,177,730	139,584,966	2018	3,223,323
Limerick 1	233,710,328	624,923,664	2027	6,560,516
Limerick 2	347,414,357	1,159,017,899	2033	7,513,814
Salem1	63,493,807	131,143,218	2020	2,516,228
Salem 2	82,302,405	197,033,864	2024	2,659,881
Total	$887,574,902	$2,402,735,133		$26,424,152

Exhibit ___(LK-12)

PECO RESTRUCTURING
OTHER TRANSITION COSTS @ 12/31/98
($000)

Discount Rate: 7.60%
Nominal Value 12/31/98: 32,661
Amortization Period: 7

Year	Nominal	Present Value
1999	4,666	4,495
2000	4,666	4,178
2001	4,666	3,882
2002	4,666	3,608
2003	4,666	3,353
2004	4,666	3,117
2005	4,666	2,896
2006		0
TOTAL	32,661	25,530

Exhibit ___(LK-13)

Exhibit JFBr-1
Schedule 1

PECO Energy Company
Overall Cost of Capital and
After-Income Tax Discount Rate
at December 31, 1996

Line No.	Type of Capital	Ratio (1)	Cost Rate		Weighted Cost Rate	Tax Savings on Long-Term Debt	After-Income Tax Weighted Cost Rate
1.	Long-Term Debt	43.1 %	8.47 %	(2)	3.65 %	1.51 % (3)	2.14 % (3)
2.	MIPS Debt	3.3	9.21	(2)	0.30	0.13	0.17
3.	Total Debt	46.4			3.95	1.64	2.31
4.	Preferred Stock	3.0	7.70	(2)	0.23		0.23
5.	Common Equity	50.6	11.60	(4)	5.87		5.87
6.	Total Capital	100.0 %			10.05 %		8.41 %

Before-Income Tax Coverage of Long-Term Debt Interest 3.64 x (5)

Notes: (1) Company provided December 31, 1996 capital structure and related ratios reflective of ratemaking deductions for unamortized loss on tenders and calls.

Description	Amount ($ bill)	Deduction	Ratemaking Capitalization ($ bill)	Ratio
Long-Term Debt *	$4.218	($0.265)	$3.953	43.1 %
Monthly Income Preferred Shares (MIPS)	0.302	--	0.302	3.3
Total Debt	4.520	(0.265)	4.255	46.4
Preferred Stock	0.292	(0.020)	0.272	3.0
Common Equity	4.646	--	4.646	50.6
Total Capital	$9.458	($0.285)	$9.173	100.0 %

* Including debt due within one year.

(2) Long-term debt, MIPS debt and preferred stock cost rates provided by the Company reflective of issuance and selling expenses as well call and tender costs.

(3) Company-provided combined federal and state effective income tax rate of 41.493%. Thus, 3.65% weighted cost rate of long-term debt x 58.507% (100.000% - 41.493%) = 2.14% and 3.65% - 2.14% = 1.51% and the 0.30% weighted cost rate of MIPS debt x 58.507% = 0.17% and 0.30% - 0.17% = 0.13%.

(4) As developed on Schedule 2.

(5) Overall rate of return of 10.05% - 3.95% total debt component = 6.10% total equity component / 58.507% (100.000% - 41.493%) = 10.43% + 3.95% total debt component = 14.38% before-income tax overall rate of return / 3.95% long-term debt component = 3.64x.

Exhibit ___(LK-14)

Exhibit JFBr-1
Schedule 2

PECO Energy Company
Summary of Common Equity Cost Rate Recommendation

		PECO Energy Company	Check Barometer Group of Nine Electric Companies (1)
I.	Discounted Cash Flow Model (2)		
	(A) Adjusted Dividend Yield	8.1 %	6.2 %
	(B) Growth Rate	2.8	4.6
	(C) DCF Conclusion	10.9 %	10.8 %
II.	Capital Asset Pricing Model (3)		
	(A) Risk Free Rate	6.8 %	6.8 %
	(B) Risk Premium	5.4	5.0
	(C) CAPM Cost Rate	12.2 %	11.8 %
III.	Average of DCF (I) and CAPM (II)	11.6 %	11.3 %
IV.	Recommendation	11.6%	

Notes: (1) The barometer group is comprised of the following nine electric companies:

American Electric Power Co., Inc.
Boston Edison Company
CINergy Corporation
DQE, Inc.
DTE Energy Company
Entergy Corp.
GPU, Inc.
Illinova Corporation
PP&L Resources, Inc.

(2) As supported by the information shown on Schedule 17.

(3) As supported by the information shown on Schedule 18.

Exhibit ____(LK-15)

Sch. 10 Adjusted Discount Rate

Capitalization	$	%	Cost (a)	Wtd. Cost
Debt	4218	44.6	7.47% *	3.33 %
MIPS	302	3.2	9.21%	0.29
Preferred	292	3.1	6.37%	0.20
Common	4648	49.1	11.60%	5.70
Total	$9,456			9.52%
			~~Tax Savings on Int & MIPS~~	(1.50)
				8.02% Disc Rate

(a) 7.47% = (342.942 − 20.621 (MIPS) − 7.211 (MIPS)) / 4218 (Exh. TPH-1, p. B-23)

9.21% = (20.621 + 7.211) / (221.250 + 80.932) "

6.37% = 18.591 / 292.067 (Exh. TPH-1, p. B-24)

* also used as return on unamortized loss on reacquired debt