PAIEUG STATEMENT NO. 1S

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	)	

SURREBUTTAL TESTIMONY

OF

STEPHEN J. BARON

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

NOVEMBER 1997

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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SURREBUTTAL TESTIMONY OF STEPHEN J. BARON

Q. Please state your name and business address.

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

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

A. Yes. I have submitted direct testimony and rebuttal testimony previously.

Q. What is the purpose of your surrebuttal testimony?

A. I am responding to the rebuttal testimony filed by PECO Energy Company witnesses Robert Clemmer, Alfred Miller, William Sundermeir, and Thomas Hill. With respect to the testimony of Messrs. Clemmer, Miller, and Sundermeir, my surrebuttal testimony

concerns their comments regarding the unbundling analysis that I presented in my direct testimony.

Mr. Clemmer has addressed the issue of the functional assignment of A&G expenses that I raised in my direct testimony and has proposed an adjustment to his original analysis. Mr. Miller has responded to the testimony I presented regarding the appropriateness of an unbundling methodology that incorporates the expected market energy and capacity rates directly into the analysis, leaving the residual as the CTC. In addition, Mr. Miller also addresses PECO's proposed unbundling methodology for Rate LILR. Mr. Sundermeir has addressed some additional rate design issues as a result of the testimony of both Mr. Clemmer and Mr. Miller and has responded, in part, to issues raised in my direct testimony regarding rate schedule unbundling. I will respond to each of these witnesses in this surrebuttal testimony.

I will also address the rebuttal testimony of PECO witness Thomas Hill regarding my recommended mechanism for the development of a just and reasonable level of stranded generation cost recovery from ratepayers.

Finally, I will briefly respond to the rebuttal testimony of Mid-Atlantic Power Supply Association witness Donald Johnstone and to the Office of Small Business Advocate witness Brian Kalcic regarding issues raised in their rebuttal testimony.

Response to PECO Rebuttal Testimony

Q. Have you reviewed the rebuttal testimony of PECO witness Robert Clemmer regarding cost of service issues?

A. Yes. Mr. Clemmer has addressed, among other issues, the functional assignment of administrative and general ("A&G") expenses and A&G plant in the cost analysis used by PECO to support its rate unbundling. He has responded to the criticism raised in my direct testimony (as well as the direct testimony of a number of other parties) that challenged PECO's assignment of a majority of A&G expenses to transmission and distribution ("T&D") functions in the Company's functionalized cost of service analysis. This functional allocation is in contrast to the allocation method (based on cost-causation) that PECO used in assigning these same A&G expenses to rate schedules. As I pointed out in my direct testimony, the Company's functional cost analysis, which should be consistent with the overall cost of service methodology used by PECO, was, in fact, inconsistent with this methodology.

Q. What is PECO's response to your criticism of the Company's assignment of A&G expenses in the functional cost analysis?

A. Mr. Clemmer has made a small modification to his assignment of A&G expenses within the overall functional cost analysis. He bases this adjustment on a survey of various cost centers within PECO that produce A&G assignments in the course of their work activities. Mr. Clemmer has indicated that he has performed a survey to determine how various cost centers will incur A&G expenses once the Company moves into a competitive mode of operation in which the generation or production side of the business is deregulated. As I understand Mr. Clemmer's testimony, a majority of the A&G expenses currently incurred by PECO will continue to be incurred by the Company after a full movement towards competition. Mr. Clemmer then utilizes this survey to make an adjustment to his previous assignment of A&G expenses to transmission and distribution functions, although he still continues to assign the bulk of these costs to nonproduction facilities. The important point of Mr. Clemmer's testimony, however, is that he now recognizes that it is improper to assign all of these A&G expenses at issue to transmission and distribution.

Q. Do you accept Mr. Clemmer's adjustment in which he has assigned an additional $31 million of A&G expenses to the production function?

A. No. Despite Mr. Clemmer's testimony and his survey results, it is still incorrect, in my opinion, for PECO to allocate A&G expenses to rate classes on the basis of a cost-causation factor that Mr. Clemmer then disregards in the class assignment of the same A&G expenses to production, transmission and distribution functions within the class. It is inappropriate to change cost-causation methodologies between the assignment of cost to the class and the assignment of the cost within the class to various functional areas. The Company's functional assignment of A&G expenses continues to be incorrect.

In addition, it appears that Mr. Clemmer's analysis of his survey results was based on an assumption that if an A&G expense is expected to be incurred for common cost functions (e.g., CFO [Chief Financial Officer] office, claims division), then these costs are assumed to be T&D related. Based on Mr. Clemmer's testimony and exhibits, there is no support for this assumption.

Q. Do the results of Mr. Clemmer's updated cost of service analysis and functional cost assignment of A&G expenses produce reasonable results, in your opinion?

A. No. A good example of why his analysis is inappropriate can be found by examining the relationship between the revised functional revenue requirement for distribution

costs within the HT rate class (Ex. RAC-10, p. 65 of 83) compared to the Company's assignment of distribution costs to HT customers in the allocated cost of service study.

In the cost of service study, Mr. Clemmer has properly recognized that a relatively small proportion of PECO's distribution facilities are used to serve HT customers. This is because many HT customers and a substantial amount of HT load is served at higher voltages. These customers do not require lower level distribution facilities. PECO has properly recognized this in the allocation of distribution cost to HT customers. Based on Mr. Clemmer's 1996 cost of service analysis, approximately 8.7% of PECO's total distribution plant has been assigned to HT customers. Likewise, approximately 7.5% of PECO's total distribution and customer service expenses have been assigned to Rate Schedule HT. Again, this reflects the relatively small amount of distribution facilities necessary to serve HT customers.

Q. Does PECO's functional cost analysis, in which it calculates each class's distribution expense, reflect similar results?

A. No. Although it is certainly reasonable to assume that the functional distribution expenses for Rate Schedule HT would bear a similar relationship to the total (for all classes) distribution expenses in the functional cost analysis, this is not the case in

PECO's analysis. Based on Mr. Clemmer's rate schedule by rate schedule functional cost analysis, distribution expenses (the total distribution revenue requirement, exclusive of return and taxes) are about $593.4 million for all rate schedules. The corresponding level of distribution expense revenue requirements for Rate Schedule HT is $91.5 million or 15.4% of the total. Clearly, the Company's functional analysis does not make sense. Based on PECO's cost of service analysis, Rate Schedule HT is responsible for 7.5% of total distribution and customer service expenses on the PECO system ($25 million). In the Company's functional unbundling analysis, Rate Schedule HT is responsible for $91.5 million of total distribution and customer service expenses. The difference of over $65 million reflects PECO's assignment of A&G expenses. This has the effect of significantly overstating the distribution rate in PECO's unbundling analysis for Rate Schedule HT.

Q. Have you reviewed the rebuttal testimony of PECO witness Alfred Miller?

A. Yes. Mr. Miller has addressed two specific issue areas raised in my direct testimony. The first issue concerns the overall methodology that PAIEUG is recommending for the development of unbundled rates and the CTC charge within each rate schedule's unbundled rate.

In my direct testimony, I proposed a methodology that considered a direct application of expected market energy and capacity rates within the unbundling analysis, leaving the residual of the rate, after subtracting out transmission, distribution, market energy and capacity rates, as the CTC. I have termed this methodology the "CTC residual" methodology. This is in contrast to PECO's method that allocates stranded cost to rate schedules (the CTC), leaving as a residual the implied market energy and capacity rate. As I pointed out in my direct testimony, the main problem with this methodology is that it produces unrealistic market energy and capacity rates in the rate unbundling analysis. This can lead to anti-competitive problems and effectively interfere with the transition into a competitive market for PECO's customers.

Q. What rationale has Mr. Miller relied on to object to your "CTC residual" unbundling methodology?

A. There does not appear to be any specific rationale relied upon by the Company to oppose the CTC residual method. However, it appears that one of the main concerns that PECO has with the CTC residual method and its reliance on a declining CTC charge in the rate unbundling is its potential impact on securitization. Mr. Miller indicates a strong concern that if a declining CTC were employed, it may not provide

sufficient recovery of an ITC charge to satisfy the requirements necessary to securitize PECO's transition bonds, if it issues such bonds.

Q. Do you believe that your proposed CTC residual methodology for rate unbundling can accommodate PECO's concerns with regard to securitization and the use of an ITC charge?

A. Yes. To accommodate Mr. Miller's concerns, I would recommend that a fixed ITC charge associated with any securitization be removed from the residual generation portion of the rate, prior to removing the CTC charge. In essence, the unbundling analysis would begin with the current bundled rate; then removing transmission, distribution and market energy and capacity charges, leaving an amount that would then be further reduced by the ITC. The resulting residual would then become the CTC charge.

Under this approach, PECO would be permitted to recover the ITC charge on a fixed basis as proposed by the Company in its securitization proceeding. However, the remaining CTC associated with stranded cost that is not securitized would be based on the residual approach that I have previously recommended and continue to recommend.

Q. On page 4, at lines 8 through 20 of his testimony, Mr. Miller states that competition is supposed to benefit consumers, not alternative suppliers. Do you have any comments on Mr. Miller's testimony in this regard?

A. Yes. This portion of Mr. Miller's testimony is in response to issues raised in my direct testimony, as well as the testimony of other parties in this proceeding, regarding the potential anti-competitive results embodied in PECO's "market price residual" unbundling methodology.

As I discussed in my direct testimony, PECO's unbundling analysis develops the market generation rate as a residual. This produces market rates that are below even PECO's expected market rates during the transition period. As a result, customers would not be able to effectively (from an economic standpoint) utilize alternative suppliers. Mr. Miller's comment in his testimony that competition is supposed to benefit consumers is correct. However, in my opinion, consumers will benefit as a result of the development of a viable competitive market that will only be possible if there are in fact alternative suppliers. Under PECO's residual market price unbundling methodology, it is quite possible that a viable competitive market will not develop during the transition period. As a result, customers will lose.

Q. Mr. Miller has indicated in his testimony that, assuming PECO's $6.8 billion stranded cost value were approved by the Commission, the CTC residual method would not be able to recover this amount of stranded cost within seven years. What is your response to Mr. Miller's comments in this regard?

A. Although I have not specifically calculated the time period in which PECO's full $6.8 billion stranded cost would be recovered using the CTC residual methodology that I am recommending, if Mr. Miller is correct, PECO does have the right to request an extension of the CTC recovery period beyond seven years (as he specifically acknowledges in his testimony). This does not, however, change my position that PECO's residual market price unbundling methodology is potentially anti-competitive and may lead to a significantly stilted development of a competitive market during the CTC recovery period.

Q. On pages 5 and 6 of Mr. Miller's rebuttal testimony, he proposes a method that would allow PECO to allocate the CTC on a levelized basis as it recommends and charge market generation prices within the unbundled rates by simply exceeding the rate cap. Is this a reasonable proposal?

A. No. Although PECO proposes to refund back to all customers who utilize PECO as a generation supplier during the transition period any excess charges above the generation rate cap, PECO's proposal would, for a short period of time, violate the generation rate cap. It is simply not a reasonable alternative to the proper development of an unbundled rate.

In addition, since customers would be well aware of the "effective" market generation rate being charged by PECO (the actual market rate less the refund), the competitive problems that I addressed in my direct testimony would still exist. This proposal, in my opinion, would not overcome the concerns that I raised in my direct testimony.

Q. On pages 8 and 9 of his rebuttal testimony, Mr. Miller discusses PECO's proposal to unbundle Rate Schedule LILR. He states on page 9, at lines 1 to 2 that "under no circumstances would the off-peak CTC be negative." Do you have any concerns with this statement?

A. Yes. If the CTC residual methodology is adopted by the Commission, as I recommend, it is quite possible that the market price in some years would exceed the generation portion (the portion remaining after the removal of transmission and distribution costs) of the HT tail block rate. By simple arithmetic, this would produce a negative CTC for

this rate block (although, for the rate as a whole, there would be a positive CTC charge when all rate blocks are considered). Since off-peak LILR usage is primarily in the tail block of Rate HT, Mr. Miller's proposal would result in an LILR customer who stays on the PECO system paying an off-peak rate in excess of the rate on January 1, 1997; in other words, Mr. Miller's proscription against a negative CTC could produce a violation of the generation rate cap for LILR customers who do not choose an alternative supplier during the transition period. It should therefore be rejected.

Q. **On page 9, at lines 17 to 23 of Mr. Miller's rebuttal testimony, he proposes an additional CTC charge for LILR customers who utilize an alternative generation supplier. This would be different from, and in addition to, the CTC charge associated with LILR service for customers who remain on the PECO system. Do you have any comments on Mr. Miller's proposal?**

A. Yes. As I indicated in my direct testimony in this proceeding, I believe that it is inappropriate to charge a CTC associated with LILR on-peak usage that is the result of purchases of supplemental energy from the PJM system and is subject to interruption. Mr. Miller's proposal in this proceeding would unbundle the LILR rate and charge LILR customers' on-peak usage a CTC based on the difference between the 1 cent supplemental energy adder (associated with on-peak LILR usage), and the distribution

and transmission delivery charges. Although I do not agree that LILR customers should pay any CTC associated with the supplemental PJM purchases, PAIEUG would accept Mr. Miller's proposed unbundling of the 1 cent adder that is currently applied to supplemental energy purchases associated with LILR on-peak usage. For LILR customers who continue to remain on the PECO system during the transition period, the overall rate cap would apply to their rate, as noted by Mr. Miller in his testimony. LILR customers who remain on the PECO system would pay the CTC associated with on-peak usage and the LILR off-peak usage charge associated with Rate Schedule HT.

In addition to these LILR CTC charges, PECO is also proposing a different and substantially greater CTC charge associated with avoided peaking capacity that would be imposed only on LILR customers who choose an alternative supplier during the transition period. Under PECO's proposal, as discussed by Mr. Miller in his testimony, LILR customers who leave the PECO system and utilize an alternative generation supplier would pay an additional peaking capacity charge associated with each customer's estimated interruptible load.

Q. Do you believe that the Company's proposal to impose an additional charge on LILR customers who choose an alternative supplier is reasonable?

A. No. The effect of the Company's proposal is to impose an additional cost hurdle on LILR customers who consider alternative generation suppliers. In essence, these customers would be deterred from participating in the competitive market until the transition period is completed since they would have to achieve market price benefits from an alternative generation supplier that not only "beat" PECO's market generation rate, but that would also overcome the additional CTC charge imposed on LILR customers who choose an alternative supplier.

This is an anti-competitive proposal that would effectively eliminate the possibility of participation in the competitive market by these customers. As a result of PECO's proposal, it is very unlikely that any LILR customer will actually choose an alternative supplier. I do not believe that this is the intent of the Competition Act. PECO's proposal should be rejected. An LILR customer who chooses an alternative supplier should pay the same level of CTC that is contained in the unbundled LILR rate that is imposed on LILR customers who continue to purchase from PECO.

Q. Are there any other considerations which would support your position that the Company's additional CTC charge for LILR customers who choose an alternative supplier should be rejected?

A. Yes. If an LILR customer actually does choose an alternative supplier and pays the additional CTC charge, this would have the effect of reducing CTC charges for all other PECO customers. This occurs because the total amount of CTC payments by PECO's customers will equal the amount of stranded cost (on a present value basis). If some LILR customers pay increased amounts of CTC costs, the CTC will terminate earlier for all PECO customers. All other PECO customers will pay a lesser amount of CTC than would otherwise be the case. As a result of the Company's differential CTC charge for LILR customers who stay and leave the PECO system, there is an effective cost-shift from other PECO customers to LILR customers who choose alternative suppliers. This is impermissible under the Competition Act and is another reason why the Company's proposal should be rejected.

Q. On page 11 of his rebuttal testimony, Mr. Miller states that, if there is no language within an existing EER contract referring to alternative access, such EER customers should then pay the full standard HT delivery charges and CTC charges. Do you have any comments on Mr. Miller's proposal?

A. This proposal, as I discussed in my direct testimony, is inappropriate and potentially anti-competitive. Because EER customers will face a greater CTC charge if they choose an alternative supplier than if they remained as a PECO customer during the transition,

such an EER customer will face a cost hurdle that may be impossible to overcome. As a result, such customers may be foreclosed from participating in the competitive market until the CTC recovery period is completed. This is inappropriate and would limit the effective development of a competitive market in PECO's service area. In addition, it may result in impermissible cost-shifting with respect to stranded cost recovery. This occurs because, to the extent that EER customers who leave the PECO system will pay a greater amount of CTC, all other customers on the PECO system will effectively pay a lesser amount than they otherwise would. Since the total amount of CTC recovery by PECO is limited to the approved level of stranded cost, there could be an effective cost-shifting as a result of PECO's EER proposal. Again, these EER customers should only pay a CTC based on the unbundled level of CTC inherent in the rates they paid as of January 1, 1997.

Q. On page 3 of PECO witness Sundermeir's rebuttal exhibit WFS-8, at lines 14 to 27, he indicates his disagreement with your methodology for unbundling PECO's HT rate. In particular, he disagrees with your use of a flat market energy charge for all HT energy blocks. Do you have any comments in response to Mr. Sundermeir's testimony?

A. Yes. I continue to believe that the most appropriate methodology for rate unbundling is to assume a flat market energy rate coupled with a capacity rate. This approach, in my opinion, is more realistic than Mr. Sundermeir's proposal to utilize an expected market energy and capacity revenue requirement, in lieu of the actual rate, in the unbundling analysis. As a result of Mr. Sundermeir's use of a revenue requirement, he is then able to compute an hours-use blocking of the market energy rate. However, it should be clear that his approach produces market energy rates that are not, in fact, market rates. The blocking constraints imposed by Mr. Sundermeir effectively remove the incremental price signal associated with the market generation rate embodied in PECO's rate analysis. This representation of the market energy and capacity price is not likely to be found in the market place and it should not be used in the unbundled rate design.

Finally, I disagree with Mr. Sundermeir's observation that high load factor customers will pay a greater rate under the generation rate cap if blocking is not done following his methodology. His observation is only correct in isolation. In fact, customers will only pay the market generation rate (contained in PECO's unbundled Rate HT) during the transition period when the CTC is also being recovered. After the termination of the CTC, PECO is free to charge any market generation rate it believes appropriate and face the consequences of the market. During the period of CTC collection, since HT

customers who remain on the PECO system during the transition period will pay both the PECO embedded market energy rate and the CTC, it is the combination of the two that must be blocked in accordance with PECO's current HT rate. In the analysis that I am recommending, the sum of the flat energy rate and the blocked CTC charge does in fact follow exactly the residual generation component of the bundled HT rate, after transmission and distribution charges are removed. This is also true under Mr. Sundermeir's analysis; i.e., the sum of the embedded market generation rate and the CTC follow exactly, by block, the residual after the T&D charges are removed from PECO's rate. As a result, since HT customers who continue to take service from PECO during the transition will pay both the CTC and the market generation rate, Mr. Sundermier's observation regarding the impact on various load factor customers is not correct. A PECO-served HT customer will pay exactly the same rate during the CTC recovery period under my recommended approach of employing a flat energy charge as such a customer would pay under Mr. Sundermier's approach.

Q. Have you reviewed the rebuttal testimony of PECO witness Thomas Hill?

A. Yes. Mr. Hill responds to the PAIEUG proposal to adjust the amount of allowed stranded generation cost by eliminating the return on equity associated with the uncollected recovery of the stranded generation cost portion of PECO's overall stranded

cost. The rationale for the PAIEUG adjustment is that such a reduction to stranded generation cost produces a just and reasonable level of overall stranded cost recovery from customers. The Commission, under the Competition Act, must determine such a just and reasonable level of stranded generation cost prior to establishing a recovery amount for the Company. Under the Competition Act, there is no guarantee of 100% recovery of stranded generation cost, unlike the provisions for net regulatory assets and qualified facility contracts ("QFs").

I continue to believe that the PAIEUG proposed adjustment, wherein the equity return on the uncollected amount of stranded cost is disallowed, is an appropriate adjustment to bring the level of stranded generation cost into line with a just and reasonable level. I disagree with Mr. Hill's characterization of the PAIEUG adjustment that it is based on an assumption that PECO would not otherwise be permitted to recover such costs under traditional cost of service regulation. This is not correct. I made no such assumption. Rather, the PAIEUG proposal is designed to adjust the calculated level of stranded cost, after mitigation, to a just and reasonable level. I believe that this type of adjustment is appropriate in the development of an overall stranded cost recovery level from customers.

Response to Office of Small Business Advocate Witness Brian Kalcic

Q. Have you reviewed Mr. Kalcic's rebuttal testimony?

A. Among other issues, Mr. Kalcic addresses the CTC residual methodology that I have recommended for unbundling PECO's rates. While it appears that Mr. Kalcic recognizes the potential benefit of a CTC residual methodology with respect to developing realistic market generation prices within the unbundled rate, he raises concerns about the relative share of stranded cost that the GS class would pay under a CTC residual methodology. In addition, he suggests that this may violate the prohibition against inter-class cost-shifting of stranded cost recovery.

Q. Do you agree with Mr. Kalcic's observations?

A. Although I continue to believe that it is absolutely necessary to unbundle PECO's rates using the CTC residual methodology, I would have no fundamental objection to Mr. Kalcic's proposed individual class-by-class tracking mechanism that would appear to overcome his concern regarding potential cost-shifting.

The potential benefits of developing an unbundled rate using realistic measures of market prices, in my opinion, outweigh any specific concerns about the relative amount of CTC recovery under the residual method that I am recommending. However, if individual rate schedules are tracked with respect to CTC recovery, this should effectively eliminate any potential argument regarding cost-shifting since each class should pay a production demand allocation-based share of the overall level of stranded cost.

Response to Mid-Atlantic Power Supply Association Witness Donald E. Johnstone

Q. Have you reviewed Mr. Johnstone's rebuttal testimony in this proceeding?

A. Yes. Mr. Johnstone has submitted rebuttal testimony in response to my direct testimony regarding the unbundling methodology that I have recommended. The first issue raised by Mr. Johnstone concerns his apparent concern that I developed unbundled rates by assuming expected market capacity prices in each year of the unbundling analysis rather than Mr. Johnstone's recommendation to utilize the highest possible capacity rate that could be justified in any given year, the cost of new capacity.

I found Mr. Johnstone's proposal to be without merit. The purpose of incorporating a market capacity rate within the unbundling analysis is to develop a realistic market rate for each year during the transition period. This market rate becomes the maximum rate that PECO can charge in any given year relative to market conditions. PECO is free to charge a lower rate, under the generation rate cap provisions. By using the cost of new capacity as the market capacity rate in each year of the analysis (as Mr. Johnstone recommends), the unbundled rate would no longer reflect any realistic measure of expected market conditions. As I indicated in my direct testimony, it is important to develop an unbundling analysis that directly utilizes the assumptions employed in the development of stranded cost for PECO. This is the approach that I have employed in my analysis. If Mr. Johnstone's recommendation were incorporated in the rate unbundling, there would be no relationship between the unbundled rate in any given year and the market price assumption embodied in the stranded cost calculation.

In addition, as a result of using the CTC residual methodology, if Mr. Johnstone's recommendation were adopted, the capacity portion of the CTC charge in any given year would be lower due to the use of the highest cost capacity rate for market price. As a result, the CTC recovery period will continue for a longer duration than would otherwise be the case. In other words, since the CTC charge associated with capacity will be lower

as a result of Mr. Johnstone's recommendation, it will take longer to recover stranded cost. His proposal should be rejected.

Q. Mr. Johnstone also addresses your use of a 4 coincident peak allocator to develop the amount of market capacity charges expected to be paid by each rate class. Do you have any comments on his testimony in this regard?

A. Mr. Johnstone is recommending that an average of the class maximum peak demand and the class 4 CP demand be used to develop the amount of market capacity costs to be used in the unbundling analysis. Mr. Johnstone has provided no evidence for his recommendation nor can he apparently cite any previous use of such a capacity allocation methodology. PECO has traditionally used a 4 CP allocator to reflect the cost responsibility for capacity on the system. It would be unreasonable to now utilize the average of the class peak and the 4 CP allocator to perform essentially the same function, assigning capacity costs to rate classes. There is no evidence to support Mr. Johnstone's recommendation. It should be rejected.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

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AND EXHIBITS

OF

RANDALL J. FALKENBERG

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
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SURREBUTTAL TESTIMONY OF RANDALL J. FALKENBERG

Q. Please state your name and business address.

A. Randall J. Falkenberg, Suite 475, 35 Glenlake Parkway, Atlanta, Georgia 30328. I am the same Randall J. Falkenberg who filed direct testimony in this case.

Q. What is the purpose of this surrebuttal testimony?

A. I will address the rebuttal testimony of PECO witnesses Hill, Bustard, Rose, Pratzon and Hieronymus.

Q. Do you have any preliminary comments?

A. This testimony is being served many months after it was originally prepared. The reason for this is that PAIEUG and other parties present their full litigation case to the PUC in the event that the Joint Petition for Partial Settlement is rejected. After this testimony was originally drafted, I updated the production cost modeling studies for the PP&L and GPU cases. These updates had little impact on the overall results of my PECO market prices and stranded costs studies and in no way alter any substantial conclusions. I have not reflected these updates in this testimony because they were not available at the time it was originally prepared. Thus, this testimony is intended to provide the PUC with a better view of the PAIEUG case had this proceeding gone to trial in August.

Q. Please begin your discussion of the PECO rebuttal filing.

A. For the fourth time in only six months, PECO has filed a new estimate of its generation market value and stranded costs. In both its direct filing in this case [in response to errors and problems raised in the securitization proceeding (the "QRO")], and now in its rebuttal case, PECO has revised its estimates to correct errors identified by PECO or the intervenor witnesses. The Company's direct case introduced a wide variety of new assumptions, most

having the effect of offsetting the legitimate "corrections" made by the Company and others that served to reduce stranded cost estimates from the original January QRO filing. This has happened again with this filing. The Company has admitted to numerous errors in the calculation of real fixed charge rates and capacity costs for new units. It has introduced new heat rates and has made a host of other corrections that largely serve to reduce stranded cost estimates. However, once again, PECO has "offset" these corrections with a new fuel price forecast, an increased cost of capital and discount rate, and has selectively adopted other intervenor criticisms (such as the A&G allocation to production) when they serve to increase stranded costs.

Q. Do you disagree with the concept of an update for a new fuel price forecast or other items that allegedly represent more recent data?

A. I recommend that if the Commission considers these studies at all, they should be heavily discounted. Updates are a one way street. Had PECO determined that the DRI Spring 97 forecast was less advantageous than the Fall 1996 forecast, it could have chosen to ignore it. The same is true of Mr. Brennan's updated cost of capital.

Furthermore, PECO had the DRI Spring1997 forecast in its possession since May before

revealing to the Commission and intervenors that it planned to file an update. This update could have probably been done earlier. At the very least, parties could have been informed that the Company planned to file this update. If the Company had been truly confident in DRI, it would have announced in April that it intended to use the new DRI forecast once it became available. Instead we are left with the unmistakable impression that PECO felt it needed to see what the DRI forecast was before deciding on whether to use it in an update.

Q. Why is this a concern?

A. The application of any fuel commodity price forecast (such as DRI) to develop long term forecasts of delivered fuel prices is not always a simple procedure. This process has room for certain judgments on the part of the analyst and requires a substantial amount of care. It is important to realize that we are not dealing with commodity fuel price inputs from DRI, but, rather, delivered fuel prices to a large number of generating units in different states, and even regions. I have not been able to check whether PECO changed the methods used in the application of the new DRI update to develop generator fuel prices. PECO's use of a new fuel price forecast is tantamount to proposing a new claim in this case.

Further, I have certain questions about the DRI Spring 1997 update given its terrible

performance in predicting the (largely historical) fuel prices in 1996 alone.

Q. Please explain.

A. The DRI October 1996 forecast projected 1996 delivered gas prices for PJM of $2.51/mmbtu [See Exhibit No.___(JFB-5)]. The actual 1996 delivered gas price in PJM was $2.96 [See Exhibit No.___(JFB-12)]. Despite missing the actual 1996 result by 18% (even though the forecast was released in late 1996), DRI *lowered* its long term natural gas price forecast. For example, the 2015 projected price for gas delivered to PJM utilities was reduced from $5.33/mmbtu to $4.82/mmbtu. Even the short term forecast (1998 to 2000) projects *lower* fuel prices now than in the Fall 96 forecast, despite the unexpected run-up in prices in 1996.

This also illustrates the problems involved in developing long range escalators. For example, the DRI Fall 1996 forecast projected a growth rate of 4.8% in natural gas prices from 1995 to 2015, while it projected only a 4.0% escalation rate from 1996 to 2015. The Spring 1997 Forecast projects a 4.3% escalation rate from 1995 to 2015, while it projects only a 2.6% escalation rate for the period 1996 to 2015. This clearly demonstrates that the starting point selected is of critical importance. Likewise, the methodology used to derive delivered fuel prices must also be consistent with the assumptions employed by DRI. We have no way of

knowing whether PECO had a substantial amount of latitude, or not, in the application of the DRI forecast to derive the PJM (and surrounding area) fuel price forecasts. In the end, we have no way of knowing whether PECO changed the method used in its application of the DRI fuel price forecast. This concerns me because in my meeting with the ICF consultants, Mr. Rose stated it was a difficult and time-consuming task to rerun the ICF model with the DRI fuel forecast. This suggests that the application of the DRI forecast to the ICF model, for example, is not a standard, easily verifiable process.

We are left with some questions regarding the application of the DRI forecast to the issues at hand, and some puzzling concerns about the reliability of the new DRI forecast itself, given DRI's poor track record in the most recent months. Finally, the pervasive nature of the PECO update suggests that the Company had ample opportunities to make (or introduce) new mistakes.

Q. Moving onto the specifics of the PECO rebuttal case, please explain how you intend to respond to the PECO witnesses.

A. The Company witnesses spend a great deal of time criticizing my testimony, but very little time responding to my suggestions for improvement of their studies. Many of the criticisms

raised by the Company witnesses are similar. Thus, my response will not always be directed at a single PECO witness. Due to the volume of the PECO testimony and the limited time to prepare surrebuttal, it has not been possible to address each and every point raised by the Company witnesses in detail. Suffice it to say, I stand by my original studies except where noted. In the few instances where I do not address criticisms made by the PECO witnesses, it does not imply that I accept their criticisms. Rather, it indicates that I believe that my direct testimony provides an adequate response, or that these points were so inconsequential or incorrect as to not merit a specific reply.

KENNEDY AND ASSOCIATES' PRODUCTION COST MODEL

Q. What is the purpose of this section of your testimony?

A. A recurring theme in the PECO rebuttal case was, as stated by Mr. Bustard, the "overly simplistic, and therefore inexact" nature of the "homemade" Kennedy and Associates Production Cost model (hereinafter referred to as the "KPC"). PECO witnesses champion the "store-bought" MAPS, ICF and EDS models and generally decry what they consider to be the low level of detail of the KPC.

Q. How do you respond to these criticisms?

A. In performing projections 20 years or more into the future, I fail to see how more complexity is per-se preferable. Further, given the volatile nature of the input assumptions, I fail to see how the "signal to noise ratio" is improved by addition of complex details. The key inputs of this type of analysis are the fuel prices, the cost of new generation resources and heat rates. Time and again PECO has corrected, revised, updated and otherwise changed these inputs, and has produced market value estimates that have differed by close to one billion dollars. It has already been amply proven that transmission limits within PJM are irrelevant. I will also demonstrate that other operational considerations, such as unit commitment considerations, are insignificant as modeled by the Company. These unnecessary details were not included in my modeling.

As pointed out above, the DRI fuel forecast was off by 18% in 1996 alone (even after much of the year had already passed). Why would one assume, given the volatile nature of fuel price forecasts, that a 20-30 year projection of production costs would gain any accuracy by inclusion of a large number of complex and unnecessary details? In the QRO, the Commission accepted my calculation of PECO's stranded costs and market prices performed without any model, only a spreadsheet. In the face of uncertainty, honest assumptions and

intelligent analysis are the best tools available to the decision maker. The less complicated, and more transparent these analyses are, the better and more useful they will be.

Second, I disagree with Dr. Hieronymus' implication that KPC has only been used in trivial regulatory proceedings, as compared to the "real world" models like MAPS that are used by utilities in actual "business" planning. The Kennedy and Associates model was used by our firm in studies for the Georgia Commission Staff to determine whether the $8 billion Vogtle nuclear plant should be completed or not. In accepting our conclusion the Georgia PSC stated that it gave greater weight to our studies (based on this model) than on the utility's studies that relied on the EPRI UPM model.

In the GSU/Entergy Merger, the KPC model was used to independently estimate merger production costs savings, despite the availability of PROMOD runs performed by the applicants. The Louisiana Public Service Commission ("LPSC") and FERC adopted "fuel-hold-harmless" provisions recommended by the LPSC staff based on my finding that the applicants' fuel cost savings estimates were grossly overstated. In addition, the applicants' proposals to allow shareholders to retain hundreds of millions in merger cost savings, while passing through to ratepayers a comparable amount of overstated fuel savings, was rejected by the LPSC. Once again this was an LPSC Staff proposal supported by the model.

The model has been used frequently in regulatory proceedings, and while input assumptions are usually debated, there has never been a single instance where a utility documented an error or inaccuracy in the model itself. Given the highly adversarial nature of these proceedings, and the large amounts of data and information I have been asked to produce in support of my testimony, I am sure that many individuals within the industry have examined it carefully.

Q. Comment on Mr. Bustard's characterization of the KPC as "homemade."

A. I am not sure exactly what Mr. Bustard is concerned about. Perhaps he would be more confident in a model developed by a large organization like GE or EDS. In the end, it is not the organization that creates the model, but rather the individuals working for it. In this regard, I can state that I authored similar probabilistic production cost models since the late 1970's that were used by one of the nation's largest architect and engineering firms (Ebasco Services) for many studies, including projects for 20 major utility clients. Many of these utilities used that model for many years. In the early 1980's I was employed by Energy Management Associates (prior to its becoming EDS Utilities) and was involved in a number of software development projects involving enhancements to the PROMOD and PROSCREEN models. I also provided training services to a large number of utilities in such

models. I believe that my qualifications are adequate to develop such models, and it would appear many major utilities agreed this was the case over the period from 1979 to 1983.

Q. Comment on the assertion that KPC has never been provided to anyone outside of Kennedy and Associates or used for any purpose other than litigation.

A. This is untrue. The current version of the KPC model has not been released outside of Kennedy and Associates.[1] However, contrary to the statements made by PECO's witnesses, earlier versions of the model have been provided to utilities and others. One municipal utility purchased an earlier version of the model in 1989, and, in at least one case, the model was provided to a utility as part of the discovery process.[2] Further, the model was used by our firm in projection of avoided costs for two major financial institutions to evaluate the reasonableness of investments in qualifying facilities projects. As noted in my direct testimony, the model was also used in a study performed for an industrial firm to analyze the decision to invest in a QF project on the PJM system. In addition, the initial version of the

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[1] This was true when I prepared this testimony in July, 1997. However, in the PP&L Restructuring case the model was provided to PP&L's consultant, NERA. In the West Penn Restructuring case, I have also provided the model to the utility.

[2] Despite the fact that the utility and its consultants signed a confidentiality agreement, the model was never returned. For this reason, I have become more concerned about the release of the model.

Monte Carlo model was provided to Georgia Power Company for testing and evaluation of our analysis of the prudence of the Rocky Mountain pumped storage plant.[3]

Q. Please describe some of the proceedings in which you have used the earlier versions of the KPC.

A. I used the model in support of my testimony in the West Penn Milesburg, et al., proceedings. In those cases I believed that West Penn did not need the capacity from the Milesburg, Shannopin and Burgettstown QF projects. While initially disagreeing, West Penn eventually attempted to escape from those contracts, and recently bought out of two of them. Apparently the model led me to the correct conclusions, even though West Penn Power didn't think so originally.

I used the model in similar APS/QF proceedings in Maryland and West Virginia, in support of a combined cycle option as opposed to QF contracts. The West Virginia Commission agreed that the QF contract in question was uneconomic. The Maryland proceeding was settled with a delay in the QF in-service date. These actions saved ratepayers from millions

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[3] While, I disagree with GPC's position, they believe that the model understates the value of pumped storage facilities. If true, then it would stand to reason that I have also understated the market value of PECO's Muddy Run plant.

of dollars of excessive costs for uneconomic QF resources. Once again, the model supported the correct conclusions regarding the choice for capacity additions long before the utility, using industry standard models, reached the same conclusions.

Q. The PECO witnesses are not impressed by your benchmark studies and claim they are illogical. Please comment.

A. I am not surprised by these comments, but disagree. Neither Mr. Bustard, Dr. Hieronymus, nor the ICF representatives even requested to see any of the support for the benchmark studies. I clearly explained to them that the process used was intended to replicate the input data assumption differences. Far from being illogical, my process demonstrates that, when I use data similar to the that used in the PECO models, the KPC produces similar results. This verifies the reasonableness of my model. The PECO experts might prefer that I be unable to "demystify" their respective models. However, I will demonstrate shortly that the secret is not so much that my model is simplistic, but, rather that there is much less going on in the various PECO models than meets the eye. In reality, the PECO models suggest a level of detail that has not actually been used in their application of the models because of the limitations of the data they employed.

Q. The PECO witnesses suggest that your benchmarks are not really that close. Do you agree?

A. I find it interesting that they criticize my results, when none of them, other than Mr. Bustard, provided *any* form of verification of their own models. Further, as pointed out in my direct testimony, the standard of comparison the KPC met was far closer than Mr. Bustard considered to be adequate when he was testing the various PECO models against PROMOD, the industry standard bearer.

Q. Has the KPC been verified against similar models in other regulatory proceedings?

A. Yes. The table below demonstrates the wide range of models the KPC has been benchmarked against and the accuracy of the results. Note that this is only a partial list, as I did not have all of the summary statistics readily available.

K&A Production Cost Model: Benchmark Studies in Regulatory Proceedings

Year	Utility	Docket No.	Utility Co. Model	Abs. % Diff.
1984	Louisville Gas & Electric	KPSC-8924	EBASCO Model	1.64%
1984	Florida Power Corp.	FPSC-830470-EI	PROMOD III	.65%

K&A Production Cost Model: Benchmark Studies in Regulatory Proceedings				
Year	Utility	Docket No.	Utility Co. Model	Abs. % Diff.
1985	Louisville Gas & Electric	KPSC-9243	EPRI EGEAS	.5%
1986	Georgia Power Company	GPSC-3554-U	EPRI - UPM	1.24%
1987	Monongahela Power Co.	WVPSC-86-524	PROMOD III	1.20%
1987	West Penn Power Co.	Pa PUC 850220	PROMOD III	1.20%
1988	Louisville Gas & Electric	KPSC-9984	EPRI - EGEAS	1.30%
1989	West Penn Power Co.	P-870216-283	PROMOD, Actual	1.00%
1989	Georgia Power Company	GPSC-3840-U	EPRI - UPM	.93%
1989	P.S. New Mexico	NMPSC - 2087	PROMOD III	.48%
1992	Gulf St. Utilities/Entergy	LPSC-U-19904	PROMOD III	.1%

Q. Please provide some examples that demonstrate the point made about the level of detail in the KPC.

A. Much was made about the fact that the KPC did not use the unit commitment logic inputs.[4] Based on my review, the "sorting" approach applied in this case by the KPC differs little in

[4] Note that the program has certain logic and options to model various situations that are controlled by inputs. I determined that it was not necessary to use these options in this proceeding. This was discussed in the meeting with the PECO representatives and is apparent in the user manual, which was made available at the meeting.

practical terms from the linear programming algorithm used in the ICF model.[5] In both cases, units are represented with a single cost, and the linear programming logic will do nothing more than sort units from lowest cost to highest cost. While ICF does have certain inputs to model "must run" circumstances (similar to an input available in the KPC), very few of these were actually used. I could have used a similar input within the KPC but saw no reason to do so. Thus, the unit commitment criticism leveled against my modeling is also a criticism of the ICF model, indicating that PECO has employed a "double standard." I also question whether the EDS PMDAM model contains complex unit commitment logic either. I understand that PMDAM does nothing more than order generators to produce "cost curves" that are then used in the Lagrangian Iteration procedure. I believe that in this process, the entire concept of unit commitment loses any meaning.

The GE MAPS model appears far more complex than the KPC, until one realizes that the much vaunted "unit commitment" logic has little practical impact on marginal costs in PHB's modeling. To understand this, it is necessary to understand a little about the nature of unit commitment logic in such models and the GE MAPS input data used by PHB. It is unclear whether PHB actually understands either of these points, or I believe Dr. Hieronymus should

[5] Aside from transmission limitations, that the more detailed models show to be irrelevant. In this regard it is interesting that the ICF model is the only model that appears to demonstrate significant transmission constraint price impacts in PJM. PROMOD IV and MAPS did not, and EDS did not even bother to model such limits.

have been very reluctant to make his criticisms of the KPC.

The primary impact of unit commitment logic is to simulate the operation of a larger number of units at lower loadings than would be the case in the simple "least cost" sorting algorithm. For example, in the modeling I performed, perhaps 10 of the non-nuclear steam units would be dispatched at full load to serve demand off-peak. In MAPS, spinning reserve requirements, and must run considerations, might cause it to simulate operation of more units (perhaps 15) running at less than full load. However, in the way that PHB implemented MAPS this makes little, if any, difference to marginal energy costs.

The reason for this is that PHB modeled all units with a single incremental heat rate regardless of unit loading. This heat rate was equal to 96% of the full load heat rate for these plants. In the original MAPS data, there was very little difference between the heat rates used for various classes of units. In addition, PHB also modeled rather limited differences between fuel prices among generators. Given this, it stands to reason that the incremental costs used in the MAPS study showed quite limited variation among classes of units. In low load hours, for example, MAPS is simulating a number of units with very similar incremental costs running at partial load. In my modeling, fewer units were running and were modeled at full load. Because it made no difference in the GE model whether the units

in question run at full or partial loading, I seriously doubt whether the GE MAPS unit commitment logic produces any real impact on marginal energy costs.[6] For example, it makes virtually no difference whether one unit is running at full load, two are running at half load, or a half dozen are running at minimum load. Had PHB actually modeled differences in heat rates within a single unit (not to mention the more substantial differences in delivered fuel prices[7] and heat rates among classes of units) such consideration might have made some difference. Thus, the real criticism made regarding the commitment logic is that the KPC makes it obvious that this input makes little or no difference, while the GE MAPS model and the ICF model hide this fact behind a complex facade. Either, the Company witnesses are being quite disingenuous, or they simply do not understand the models that they are using. Neither explanation suggests the Commission should afford much weight to these PECO witnesses' comments.

Q. Are there any other impacts of the more complex linear programming or unit

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6 Unit commitment logic *could* make a substantial difference in marginal capacity costs if an "offset" method were used because periods of minimum or low load operation of new CTs or CCs would offset profits from periods where these units run at full load. Dr. Hieronymus chose not to use this method.

7 In this regard it is interesting that Dr. Hieronymus also criticizes my use of actual historical delivered fuel prices (that vary substantially among plants) and recommends the use of spot prices (which will vary far less across locations). His use of spot prices tends to further mute any impacts of unit commitment considerations. Dr. Hieronymus is guilty of proposing mutually exclusive criticisms.

commitment logic used in the various PECO models?

A. I doubt it. Aside from having virtually no impact on the market price results, these additions do make the programs run much slower, increase data requirements, and increase the apparent complexity of the models. In the end, this probably makes it much more difficult for the user to detect errors in logic or input assumptions.

Q. Is there any evidence to suggest that this occurred in the QRO or the instant case?

A. Absolutely. These proceedings are rife with examples of the Company witnesses failing to correctly apply the models they have selected. What better example could one ask for than Dr. Hieronymus' studies? In the QRO, Dr. Hieronymus incorrectly specified the amount of combined cycle generation and admittedly understated market energy prices by hundreds of millions of dollars. He was able to only partially correct this in the rebuttal phase of the QRO. Originally, in this proceeding he used an all gas-fired combustion turbine scenario in MAPS. However, Dr. Hieronymus computed the capacity credit based on oil-fired CTs. This is significant because Dr. Hieronymus' workpapers show that oil-fired CTs have a lower capital cost, while gas units have lower fuel costs. Dr. Hieronymus assumed capacity prices based on low cost oil-fired units, but computed energy prices assuming only gas-fired

CTs were actually built. Dr. Hieronymus has finally corrected this mistake by upping his CT capacity cost by a modest (and I believe inadequate amount) to account for the cost of gas pipelines.

Dr. Hieronymus and his team at PHB did very poorly in their calculation of real fixed charge rates. In fact, Dr. Hieronymus now apparently admits that his real fixed charge rate was wrong and has given up on even trying to compute one. Instead, he now adopts the OCA figure. I am not confident of the PHB modeling of unit commitment, and as pointed out in my direct testimony, PHB's model shows serious anomalies in the modeling of pumped storage plants and combustion turbines.

Likewise, the EDS model contained gross errors for the heat rates of certain units. For example, Mr. Bustard has admitted that the Hay Road and Bergen plants had completely erroneous heat rates in the original filing. Of course, the gross EDS error in computation of the real cost of new plants is also well known in this proceeding, and does nothing to inspire confidence in the myriad of "little" inputs, such as those that impact unit commitment logic. In the end, this is much ado about nothing. PECO's witnesses are grasping at straws to find criticisms of the KPC model because they simply do not like the results and have nothing of substance to discuss.

Q. In regard to unit commitment logic, what types of inputs are required and do you believe PECO has valid data?

A. A full modeling of unit commitment requires data concerning minimum down times for every generator modeled, minimum start up times, unit ramp rates, start up costs, data concerning a wide range of transmission interfaces, local transfer limits, and load models that accurately predict the future loads 8760 hours each year for 20 years at more than 1000 load busses in PJM alone. I do not believe that PECO has reasonable information for any of the needed unit specific data for plants other than its own. Mr. Bustard championed the EPRI TAG (the 'utility industry's Bible' according to Dr. Hieronymus) as a source for such data. However, TAG data is very generic, deals mainly with new technologies, and is unlikely to shed much light on data specific to units built in prior decades.

Q. A number of the PECO witnesses' criticisms relate to the modeling of "marginal units" and the simulation of peaking and emergency generation. Do you have any comments?

A. Simulation of marginal units (higher cost intermediate and peaking capacity) is a challenge for any model. The same is true of the simulation of emergency generation. I recognized this and insured that my results would be relatively insensitive to such factors. I did this in

three ways. First, I did not model any fuel savings benefits for PECO's CTs even though the strict model results suggested some might exist for these units. Second, I used a methodology where capacity costs of combined cycle units were developed based on offsetting the fuel savings of such units against this capacity cost. Thus, to the extent that peaking generation energy costs might be overstated, the effect is an offset against capacity costs. The end results are virtually unaffected by the cost of emergency or "last resort" generation resources. I verified this conclusion by performing test runs varying this input. Even a reduction of nearly 50% in the cost of "last resort" generation had virtually no effect on PECO's stranded costs.

Finally, I carefully examined my results to ensure that the most realistic modeling possible was performed for marginal units. In the case of PECO, I am satisfied that my modeling is both excellent and vastly superior to that performed by the Company.

Q. Please explain.

A. The figure on page 25 and Exhibit No.____(RJF-12) summarizes the results of my modeling for 1995 for PECO's marginal units. This includes the combustion turbines, Cromby 2, Eddystone 3 and 4, Schuylkill 1, and Delaware 7 and 8. The only changes made in the data

were to match 1995 NUG generation with actual and to accept Mr. Bustard's recommendation to increase on-peak NUG generation. The first change was made because my modeling assumed the higher NUG generation levels used in 1999, and beyond. (The changes in NUG generation made little difference and does not "improve" the results or substantially impact stranded costs). The figures demonstrate an excellent correlation between the generation of these marginal units in the model compared to 1995 actual. For example, PECO's CTs produced 171 gWh in 1995, while the adjusted KPC projected 113 gWh. This is significant because it is the generation of such peaking units that is the closest measure of the very highest cost energy required in PJM. All in all, the model is projecting operation of the least efficient units on the PECO and PJM systems that are quite close to (albeit below) the historical levels. Naturally, the model did not perform perfectly. However, it did do an excellent job of replicating the actual generation of most of the marginal units.

Q. How do PECO's simulations compare to the 1995 actual?

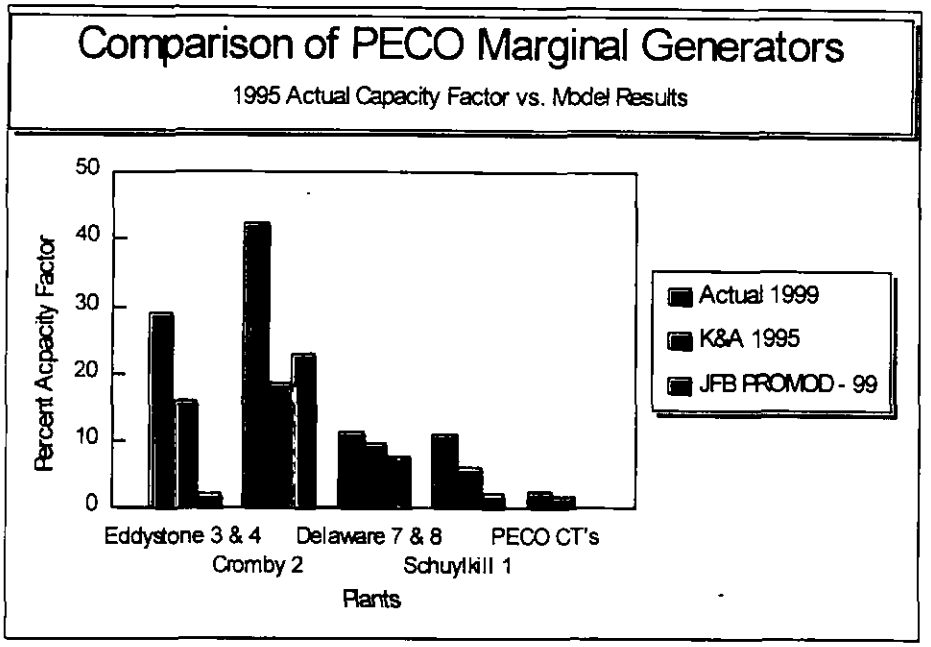
A. Quite poorly. PECO did not actually present any 1995 results, however, comparison of 1995 actual to 1999 projected is enlightening. Mr. Bustard presented a PROMOD IV simulation in Exhibit No.___(JFB-10) that demonstrates how poorly the PECO modeling (using the so

called "real world," "store bought" models) actually performed. For example, Mr. Bustard projected that in 1999, PECO's CTs would produce only 3.5 gWh, or only about 2% of the actual 1995 generation.

As noted elsewhere, PECO's other models all predicted little or no CT generation for 1999 or beyond. Given the decline in reserve margins projected between 1995 and 1999, this substantial decrease in peaking generation is not just hard to understand, it is indicative of a serious set of problems in the various PECO models.

Both Mr. Bustard's PROMOD IV and PMDAM projections for the operation of Eddystone 3 and 4 are completely unrealistic. For 1999, Mr. Bustard's PROMOD IV run projects only 125 gWh and PMDAM projects absolutely no generation for Eddystone 3 and 4 (despite assuming the unit would run 100% of the time on gas). The actual 1995 generation was about 1,900 gWh, some 15 times more than Mr. Bustard projects for 1999, in the best of his two models. Likewise, the ICF model drastically under predicts the generation of Eddystone 3 and 4, projecting less than 700 gWh (36% of 1995 actual) for 1999. The KPC was also too low for Eddystone 3 and 4 (1063 gWh), but closer than three of PECO's models. Incidently, Mr. Bustard indicated to me during one of our conversations that he believed that the 1995 generation for Eddystone 3 and 4 was somewhat higher than normal. Thus, I believe that my

results make perfect sense.



Q. Does the fact that Eddystone 3 and 4 never run in Mr. Bustard's PMDAM model (and seldom run in the ICF IPM model) raise any "red flags"?

A. Absolutely! Based on the 1995 EIA heat rates and PJM fuel prices, there is more than 14,000 mW of capacity with a higher full load cost than Eddystone 3 and 4 in PJM. If Eddystone 3 and 4 never run, we can only assume that this higher cost capacity in PJM doesn't run either. Thus, the EDS model is predicting that somehow PJM utilities will serve loads with nearly 30% of all capacity idle for the next 30 years. There is no explanation for

this anomaly. Based on my discussions with Mr. Bustard, I believe that the real reason for assuming Eddystone would operate 100% of the time on natural gas was a futile attempt to get the PMDAM model to show at least some generation from these units. Further, the greatly understated projections of operation for Eddystone 3 and 4 casts great doubt on the ICF and PROMOD IV projections for the same reasons.

Q. How does your modeling compare to the actual 1995 results and to PECO's model results for other units?

A. For Cromby 2, the KPC is also lower for 1995 than actual, and about the same as the 1999 PROMOD IV result. None of the other three PECO models project that Cromby 2 will run in 1999. For Delaware 7 and 8, the KPC predicted 1995 generation of 212 gWh, compared to actual of 249 gWh. PROMOD IV predicted only 167 gWh, or 67% of 1995 actual for 1999. Given the decline in PJM reserve margins, it would be logical to assume generation for all PECO units would increase by 1999. For Schuylkill 1, the KPC under predicted 1995 actual (86 gWh vs. 159). However, this result was far closer than Mr. Bustard's PROMOD IV result (29 gWh or 18% of 1995 actual) for 1999. Once again, the EDS, ICF and PHB models simply assumed (or projected) that these less efficient units would not run at all.

Q. How well does the KPC model PECO's combustion turbines?

A. I believe the KPC model results are excellent, if not outstanding, while the PECO models are uniformly abysmal. In 1995, PECO's CTs produced 174 gWh. The original run KPC predicted 142 gWh and the adjusted run predicted 113 gWh. As noted elsewhere, these units produced almost no energy in the PROMOD IV, MAPS, IPM or PMDAM simulations. It is also worth noting that the PP&L CTs also were predicted quite well by the KPC. In 1995, these units generated 23 gWh, while KPC (as adjusted) predicted 36 gWh. The KPC also did a good job of predicting the generation for PP&L's Martin's Creek oil units, and as in most of the other cases, underpredicted the actual results.

I believe that the evidence indicates the KPC never seriously over predicted generation from any of the PECO marginal units, and while occasionally below actual, was almost always far closer than any of the PECO models.

Q. Why is the prediction of generation for marginal units significant to estimates of marginal costs?

A. The hydro and nuclear plants, as well as the most efficient coal plants and NUGs, run fully

loaded whenever possible. All reasonable models will predict this. The generation of such units is controlled by the input availability factors alone and, for this reason, does not really provide a test of the model's predictive powers. The less efficient units on the system are the ones setting the marginal energy costs. Accurate replication of the generation of these units therefore is a significant indicator of reasonable marginal cost estimates. The PECO models have all failed miserably on this score.

Q. What about Mr. Bustard's comments about the alleged overestimates of power outages?

A. The model is not predicting power outages. Rather, it models a brief need for additional resources or tie line support. In a probabilistic model there is always some chance that multiple contingencies will result in a system-wide outage or a need for tie line support. In addition, interruptible loads, load management, voltage reductions, emergency generator ratings, and other measures will be used. It is further possible that the 1600 mW of pumped storage capacity in PJM could be rescheduled to accommodate short term requirements. I did not model these options, and had I done so, it would have had little or no impact on market prices. As noted above, my modeling of the least efficient peaking resources on the PECO (and PJM) system is far superior to that presented by PECO.

Q. Could you place this issue in perspective?

A. Yes. For 1999, the KPC indicated that additional energy resources (either tie line support, load management, short term purchases, or interruptible loads) would be required to provide less than .1% of total energy requirements. This is negligible by any standard. Inclusion of such resources would have had no impact on my model results.

Further, the least efficient generator I modeled in PJM was the PSE&G Hudson 3 unit. I projected a capacity factor for this unit in 1995 of 1%, compared to an actual capacity factor of .04%. This is hardly much to get excited about, particularly when PECO's models missed the generation of certain major units (such as Eddystone 3 and 4) by a huge margin, and considering the excellent representation of PECO's peaking units in my modeling.

Q. Did your modeling overstate the generation of other high cost PJM units?

A. No. For example, GPU's 19 mW Blossburg unit is the fifth least efficient unit in PJM. In 1995, it ran with a 1.5% capacity factor (and ran for 148 hours). In my models it ran for about 100 hours and operated with a 1% capacity factor. It is the very tip top of the PJM load curve that PECO is disputing, and it has no impact on market prices for generation in

the modeling I have performed.

While I would naturally like to try to get each unit's generation as close as possible, the analysis I have performed suggests that, if anything, my modeling understates the output of most higher cost generators in PJM. PECO's models don't even come close on many of the intermediate cost units and show virtually no operation at all for most of the peaking and highest cost resources. I recommend that the Commission decide whether it would prefer a model that misses the very highest cost resources in PJM by a negligible amount, or models that completely miss the mark on some of the more efficient cycling units in the pool.

Q. Please summarize this point.

A. I simply ask the Commission whether it would prefer to rely on a set of models so complex that even PECO's experts are unable to apply them without a number of admitted input data errors, counterintuitive results and poor correlations to actual historical data. In the end, the simpler model seems to do a much better job replicating the "real world" results than do the PECO models.

Q. Let's turn now to some specific criticisms made by PECO witnesses. Do you have any

comments regarding Mr. Rose's contention that your Monte Carlo model results indicate problems exist in your probabilisitic model?

A. Mr. Rose observes that the Muddy Run plant operates with about the same capacity factor as one of the PECO marginal units, Delaware 7. He opines that this means that both units should have the same market price. However, this is simply wrong because he failed to realize that a pumped storage plant's fuel costs vary throughout the year. Muddy Run will run on any day when the cost of off-peak pumping energy plus losses is lower than the cost of on-peak generation. For example, on a typical April day in 1999, the unit is pumped at a cost of $13.5/mWh and generates with a value of $19.8/mWh. On a typical July day, the pumping cost is $19.7/mWh, while the value of generation is over $60/mWh. On an annual average basis, the average market price for generation is computed by taking the average of *all* days' results when the plant operates including many days when pumping costs (and generation market prices) are quite low. However, the pumped storage plant can only operate 8 hours per day in my modeling. Thus, it may miss certain peak price hours in winter and summer months or during periods when larger units are down (thus making the cost of pumping prohibitive). During these situations, conventional steam plants would be able to operate. Thus, the two types of units should be expected to have differing prices even though they may operate at the same capacity factor.

Given the assumptions of the ICF model (which allow a pumped storage plant to pump in April and generate in October), I find this criticism indicative of a "double standard" being applied by Mr. Rose. Considering also that Muddy Run and Eddystone 3 and 4 ran at about the same capacity factor in 1995 (29% for Eddystone 3 and 4 and 23% for Muddy Run), I would be interested in Mr. Rose's explanation as to why he projects that the steam plant will run at only a 6% capacity factor in 1999, and the capacity factor for the pumped storage plant will drop to 15% in 1999.

Q. Comment on Mr. Bustard's suggestion that you should have shown more hydro, NUG and import generation in peak periods; do you agree?

A. Mr. Bustard has a valid, but inconsequential, point. It does stand to reason that NUGs, in particular, will attempt to schedule their generation to coincide with higher price periods. Similar comments will apply with respect to hydro generation where some storage is present (such as the Conowingo facility). I performed a run to test this suggestion and it had a negligible impact on my results.

Q. Explain why these sorts of adjustments have little impact on market prices.

A. PECO's witnesses seem to have concluded that by "overstating" the amount of intermediate, peaking[8] and emergency generation, I have overstated market prices. However, apparently they have failed to comprehend the dynamic nature of my modeling. If peak period generation increases and prices are "too high," then capacity prices will be depressed. Overall market prices will be largely unaffected. All that will change is the relative proportions of capacity and energy prices. Further, if energy prices are lowered, then the modeling would indicate that combined cycle units are uneconomic. Re-optimizing the capacity expansion plan with more CTs will serve to increase market energy prices. My own simulations have confirmed this many times. Once again, this fact was explained to PECO's representatives at our discovery meeting in Atlanta, but, they apparently failed to understand it or simply preferred to ignore it.

Q. Do you find anything new regarding the issue of average and incremental heat rates?

A. No. Dr. Hieronymus simply restates his earlier erroneous position. PECO introduces two new witnesses, Mr. Rose and Mr. Pratzon. Mr. Rose uses average heat rates, while Mr. Pratzon recommends incremental heat rates. While Dr. Venkateshwara did not file any

[8] In this case the term "overstated" is apparently to be measured against PECO's models, not actual data as discussed above.

rebuttal testimony, he will be participating in the hearing and continues to use the average heat rates. I dealt with this issue in depth in my direct testimony and see no reason to restate the discussion here. The fact that the current, temporary, PJM rules limit bids to incremental cost, and allow for an uplift payment, is irrelevant as discussed in my direct testimony.

Q. Do you find Mr. Pratzon's suggestion that current PJM pool rules utilize the incremental rather than average dispatch costs to be persuasive?

A. No. Mr. Pratzon assumes that the temporary PJM rules will stay in effect for the next 30 years without change. I addressed this issue in depth on direct, pointing out that there is nothing requiring PJM members to make bilateral trades at incremental cost. Further, even Dr. Hieronymus has testified that the problem of negative cycles will result in *either* an uplift mechanism or bidding at prices above incremental costs. Finally, the current PJM rules also require a capacity deficiency payment of $58.40/kW, a price estimated by the PJM Operating Committee to be equal to the cost of new peaking capacity. If PECO would like to assume that current PJM rules stay in effect for the next 30 years, it should also assume that capacity prices remain at $58.40 /kW (in real terms) for this period as well.

Q. Is there a simple resolution to this issue?

A. Yes. If PECO is unwilling to accept my position on this issue, then it simply needs to certify that it will never charge any customer, or present any bid to the PJM ISO over the period 1999 to 2029, at a price higher than incremental cost (as currently defined by PJM Pool rules). PECO also needs to obtain a similar certification from all other PJM members. PECO should also change its PJM restructuring proposal to indicate that it no longer supports the concept of including all start up and no load costs in bid prices. PECO also needs to develop a mechanism to audit bids to assure that no bid will ever exceed the current definition of incremental cost, and develop a refund mechanism to refund any and all overcharges. In addition, PECO should withdraw the ICF testimony and the EDS runs because ICF uses average heat rates, and EDS uses neither the uplift mechanism currently defined in pool rules, nor does it use average heat rates. Finally, as noted above, PHB should use a capacity credit of $58.40/kW (in 1997$) for the remainder of the study period.

FUEL PRICE ISSUES

Q. Do you have any comments regarding the fuel price criticisms made by Dr. Hieronymus?

A. Dr. Hieronymus is wrong about fuel costs for several reasons. First, he is wrong that my

approach systematically overstates delivered prices. I compared my average fuel prices for the base year with the DRI and EIA 1995 base delivered prices for PJM. The EIA average delivered fossil fuel price for electric generators in the Mid Atlantic region for 1995 (the EIA base price) was $1.63/mmbtu. My model used a PJM average delivered fuel price of $1.657/mmbtu. Thus, my base prices are in line with the EIA base prices and are appropriate for long term forecasts. For natural gas (probably the most significant fuel over the long term) my 1995 average base price was $2.04/mmbtu, compared to $2.10 for EIA.[9] There is no systematic bias in my base price figures.

Dr. Hieronymus is also incorrect in his implication that there will be a systematic difference between contract prices and spot prices. This may be true now because the coal markets are soft. However, over the long term there will be little difference in contract and spot prices. My fuel price figures are consistent with the EIA long term forecast, thus reasonable for these purposes.

Dr. Hieronymus is incorrect in his characterization of pipeline delivery charges and coal delivery charges as fixed not incremental. These are classic examples of costs that are

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[9] I also mentioned all of these facts to the PECO representatives at our meeting, but again they were ignored.

variable in the long run. This simply means that if a utility is not recovering these costs it will eventually drop the resource out of the marketplace, thus producing upwards pressure on prices.

This is particularly true in the case of new generators. Why would anyone invest in a new gas-fired combined cycle or combustion turbine power plant under the assumption that the marketplace will not allow recovery of pipeline demand charges? In this regard it is interesting to note that GPU in its restructuring filing adds a $10/kW year charge to combined cycle O&M estimates to account for such delivery charges.

In the end, most of these issues center on the question of whether, over the long run, prices will be sufficient to recover long run marginal costs or not. I believe that they will. The PECO witnesses selectively apply their own definition of short run marginal costs to systematically assure that prices always fall short of long run marginal costs. The assumption that prices would always equal short run marginal costs was one of the points I raised in the QRO, and I believe that the Commission order in that case accepted my position on these matters.

CAPACITY COST FOR NEW UNITS

Q. The PECO witnesses once again criticize your capacity cost estimates. Is there anything new in this regard?

A. Not really. PECO prefers to make a number of rosy assumptions about the future improvements in technology and, as a result, is asking ratepayers to provide an additional stranded cost "hedge." In effect, they believe ratepayers should insulate PECO from the risk that possible future competitors would be more efficient than current competitors. Future technology improvements are certainly not known and measurable, and may be just as likely to benefit PECO's plants (through reduced O&M, A&G or other costs) as possible competitors. For example, PECO assumes that all plant O&M expenses will remain at constant 1996 dollar levels and that A&G expenses will likewise increase with inflation. PECO assumes no productivity improvements when it comes to its own operations, despite the assumption that it will invest literally millions of dollars for plant capital additions. Further, PECO has totally ignored the possibility of combined cycle re-powering of some of its older plants. Re-powering is a technology that would enable the Company to capitalize on the assumed efficiency improvements in combined cycle generators. This suggests PECO has greatly understated the value of many of its older plants. Instead, the Company assumes

that for the most part these units will never run in a competitive market.

Q. Did you notice that Dr. Hieronymus has made yet another revision to his capacity cost estimates?

A. Yes. Dr. Hieronymus has increased his CT costs to include some of the heretofore excluded costs. However, he has now switched from oil to gas fuel for the generic CT used in his calculation of capacity credits. As discussed above, he apparently did so to be consistent with his MAPS simulations. While it may appear that his new CT cost estimate of $298/kW is close to my estimate of $300/kW, my estimate is for an oil-fired unit, and would not include gas pipeline costs. I believe that $298/kW is much too low for a generic gas-fired CT because of the pipeline costs. I believe it is also unlikely that many suppliers would build a pipeline just for a merchant CT plant. The pipeline needed to serve a CT would be identical to one required for a combined cycle unit of much larger capacity. The CT units would run much less, and still be subject to interruption. Recovery of the incremental pipeline costs would be quite risky given these circumstances. Further, pipeline costs are very site specific and it is really impossible to estimate a generic figure that would apply in all situations. Dr. Hieronymus' pipeline allowance is only $4.4 million. He is assuming that all new generators could be built within 5 miles of a gas pipeline and 10 miles of an electrical

transmission line. However, BG&E recently completed gas-fired CTs at its Perryman site. BG&E estimated the cost of the pipeline at that site to be around $50 million. A recent PP&L study estimated the cost of a pipeline for 100% gas firing of the Martins Creek units 3 and 4 to be even more for the pipeline itself and compressor stations. It is interesting that PP&L estimates the cost for a gas-fired CT to be $338/kW, while GPU in its restructuring filing estimates the cost at $350/kW. Incidently, GPU also assumes that even gas-fired CTs with this added pipeline investment will be interrupted during the winter peaking season. GPU recently completed a new gas-fired unit, Portland 5, at an existing site at a cost of $330/kW. Finally, let us never forget that until Dr. Hieronymus corrected the errors in his QRO model, he was satisfied with using a cost for gas-fired combustion turbines of $360/kW. Dr. Hieronymus' *original* estimate ($360/kW) for a gas-fired CT is still credible and much closer to the estimates used by PP&L ($338/kW) and GPU ($350/kW) than his latest *estimate du-jour ($300/kW)*.

Q. Do you have any general comments regarding Dr. Hieronymus' latest revisions?

A. Yes. Dr. Hieronymus is PECO's "flagship" witness on market prices. Recall that PECO relies on the PHB market price study for its "official" stranded cost calculation. The revisions made by Dr. Hieronymus at this time mark the third enormous set of corrections

to his modeling effort. Recall that in the rebuttal phase of the QRO, Dr. Hieronymus entered a correction to his study of roughly $400 million. At that time, even Dr. Hieronymus admitted he was uncertain whether that was a complete correction. In his direct testimony in this proceeding, Dr. Hieronymus completed his correction of the error in the expansion plan of his MAPS model and also corrected his nuclear capacity factor assumption. That amounted to an additional $900 million in market value. However, he offset those legitimate corrections with a new set of unjustifiable assumptions on capacity prices that lowered the market value by approximately $500 million. He has now admitted to another $515 million in new errors (largely the understated capacity costs), but, once again, offset these with a new fuel price forecast. In addition, just as in the QRO rebuttal phase, I do not believe Dr. Hieronymus has actually gone the full distance required to correct his errors. However, at this point, I question whether there is any benefit in further analysis of the PHB study. In the past, anytime an error has been identified, Dr. Hieronymus apparently offers a partial correction, then adjusts another unrelated assumption.

Q. PECO's witnesses all criticized your inclusion of variable O&M expenses in the capacity cost of new CTs. Is this significant?

A. No. I included $1/kW annual variable O&M for a new CT in its total O&M expense as an

allowance for variable O&M in my modeling because I did not specifically model variable O&M in my market energy cost. As is apparent from my response to PECO's interrogatories, the primary impact of the capacity cost of a new CT is to establish a "ceiling" on market capacity prices. The only other effect is that it impacts the relative economics of CTs versus combined cycle plants. My resulting capacity mix was 100% combined cycle, and in nearly every year, the cost of combined cycle generation (less fuel savings) fell much more than $1/kW (plus escalation) below the CT ceiling price. As a result, removing the $1/kW would have virtually no effect. Simply removing the $1/kW from the 1995 base CT capacity price would decrease the market value of PECO generators by only $13 million.

Q. Did you make the same adjustment for combined cycle O&M?

A. No. For combined cycle units I used ICF's fixed O&M figure. Thus, I assume that Mr. Rose, at least, is not criticizing my modeling of combined cycle unit O&M. However, I was aware that ICF's combined cycle fixed O&M was higher than the figures used by PECO's other witnesses. My exclusion of variable O&M from market energy prices in general more than compensated for this, even assuming that the other PECO witnesses were correct in their fixed and variable O&M estimates. I attempted to explain this to PECO's representatives at our meeting and they seemed to understand. However, now they suggest

my approach is incorrect. This concerns me because I actually assume lower combined cycle O&M than any of PECO's witnesses. It appears that PECO is criticizing me for using figures lower than those supported by their own witnesses, and Mr. Rose is criticizing me for relying on Dr. Venkateshwara's figures.

Combined Cycle Plant Direct O&M (96$)

	Fixed $/kW	Variable $/mWh	Annual Cost @80% CF
Falkenberg	**17.1**	**0**	**17.10**
ICF	**17.1**	**Not Reported**	**17.10**
EDS	**7**	**2**	**21.02**
PHB	**9.2**	**1.3**	**18.31**

Q. Do you have any comments regarding Mr. Bustard's assertion on page 23 of his rebuttal that your CT fixed O&M is "too high"?

A. Once again, Mr. Bustard provides no real support for this assertion. In this case, it is interesting to compare PECO's O&M assumptions for its own units to those used in my study and those recommended by PP&L and GPU in their restructuring filings. The table below

demonstrates that PECO has not only used the lowest CT fixed O&M assumptions of any source (including PP&L and GPU [10]) for competitive units, it has also used much higher figures for its own CTs as shown in Mr. Hill's exhibits.

Comparison of CT O&M Costs

Source	Total CT $/kW Fixed O&M A&G, Capadds
RJF	**$ 5.5**
EDS	**$ 2.0**
ICF	**$ 1.9**
PHB	**$ 2.0**
Tom Hill*	**$14.0**
PP&L**	**$ 5.0**
GPU	**$ 8.1**

*** PECO Existing CTs**
**** PP&L Corrected (Originally $9.0/kW)**

Q. Mr. Rose and Mr. Bustard both criticize you for not imputing fuel savings to the combustion turbine component of capacity prices. Are they correct about this?

A. No. I find this to be another *interesting* but unfounded criticism. First, I would like to point out that PECO cannot make a valid case for both this adjustment and the assumption that

[10] Note that the GPU figures also include property taxes, but would still exceed PECO's estimates without this adjustment.

units will bid at incremental cost. The reason is that if CTs bid at incremental cost they will lose money on energy sales. This will occur because they will be dispatched for many hours at inefficient loadings and fail to recover all fuel costs. With an uplift payment they would break even, at best. This is confirmed in the MAPS modeling of PECO's own CTs, for example. With respect to this point, PECO cannot have it both ways.

Second, I believe this criticism may stem from a misunderstanding of my methodology. In the case of Mr. Rose, it appears he got this mis-impression from reviewing my spreadsheets and did not review my response to PECO's data request where I explained the methodology used. What is so fascinating about these criticisms is that Mr. Rose and Mr. Bustard are criticizing me for using the same method that Dr. Hieronymus and Dr. Venkateshwara use.

The method I used was to compute capacity prices by comparing the cost of new combined cycle generation to the cost of "pure peaking capacity." I offset the fuel savings of a combined cycle unit against its capacity cost (and not, as incorrectly assumed by Mr. Rose, against the cost of a CT). I then compared that result to the cost of pure peaking capacity (assumed to be a relatively inefficient oil-fired CT). If the cost of the combined cycle plant capacity less fuel savings exceeded the cost of a pure peaking plant, I limited the price to the CT annual fixed cost. This is identical, I believe, to the method described by Dr.

Venkateshwara in his direct testimony on pages 7-8. I also understand from my discussions with the EDS consultants in Atlanta during the QRO that PMDAM uses the same method. Finally, it is obvious that Dr. Hieronymus uses nothing but the capacity price of a new CT without any adjustment for possible fuel savings of combined cycle plants. Unlike the PHB and ICF studies, I actually allowed the price of capacity to drop below the combustion turbine "pure peaking capacity" cost. Now, PECO's witnesses suggest that I should further reduce the combined cycle cost for capacity because the underlying CT plants might produce some additional fuel savings. The PECO witnesses simply do not like their own method.

Q. Why do you believe PECO's witnesses made this mistake?

A. I suspect they simply did not understand the spreadsheet calculation I provided. In the spreadsheet I compute the market price of capacity as follows:

Market Price of Capacity = CT Capacity Price - (Combined Cycle "Profits"); with the "Profits" never allowed to be negative.

Mr. Rose and Mr. Bustard are suggesting that if the combustion turbine plant also produces energy profits, the above formula would be reduced further. From the above equation, it may

appear that the cost of CT capacity price impacts the analysis. In fact, it was apparent to me that the PECO witnesses misunderstood the calculation because of the way they worded their data request on this subject. It should have been clear from my response that the combustion turbine price only sets a ceiling on the market price of capacity. The calculation of "profits" is as follows:

Profits = Combined Cycle Energy Margins - (Combined Cycle Capacity Cost - CT Capacity Cost).

As explained in my response to PECO's data request, the actual formula used is as follows after the "Profits" are inserted into the equation:

Capacity Price = CT Capacity Cost - [Combined Cycle Energy Margins - (Combined Cycle Capacity Cost-CT Capacity Cost)];

After the substitutions are made and terms canceled:

Capacity Price = Combined Cycle Capacity Cost - Combined Cycle Energy Margins; not to exceed the capacity cost of a CT.

Q. Why did you use the procedure above?

A. I wanted to be able to quickly determine whether combined cycle unit fuel savings were sufficient to justify installation of such units instead of a CT. Recall that it was this very area where Dr. Hieronymus made his mistake in the QRO proceeding.[11] As a result, it was reasonable to look at the relative cost of a combined cycle plant. The model allowed me to determine if the added combined cycle investment over and above a CT was cost justified, given a market that already had a substantial amount of new combined cycle generation in the mix. Because the model generally confirmed this situation existed, I added combined cycle units exclusively to the PJM capacity mix in future years. Inasmuch as a combined cycle unit really represents nothing more than a combustion turbine with some additional facilities connected to harvest waste heat, the method I use implicitly considers the fuel savings of both the combustion turbine and combined cycle portions of these new plants. Once again, I believe that this is entirely consistent with the method used by PECO's witnesses, including Dr. Venkateshwara, who neither Mr. Bustard nor Mr. Rose chose to criticize.

[11] In fact, Dr. Hieronymus' real mistake was that he simply did not include a provision for such an adjustment in his analysis. Had he done so he would have immediately seen the problems with his capacity mix assumptions.

Q. Is there any alternative method that might be used to accommodate the "fuel savings" of pure CTs in your analysis?

A. Possibly. Perhaps Mr. Rose is suggesting that combustion turbine plants might be built for fuel savings in addition to the traditional reliability considerations. In effect, it might be suggested that a combustion turbine plant would be built prior to the time when capacity prices are sufficient to recover the full cost of a new plant. I consider this to be a highly dubious proposition for a number of reasons. First, unlike a combined cycle plant that will run most hours of the year, CTs will operate with low capacity factors, would cycle far more frequently and would have rather unpredictable profits. Profits for such plants will be far more susceptible to fuel price or weather variations. In addition, the energy profit margins of such plants would be much smaller than for a combined cycle plant. An increase in gas prices might increase profit margins for a highly efficient combined cycle plant, but do nothing for a standalone CT. A gas-fired CT would require the same pipeline capacity investment as a full scale combined cycle plant. Further, the types of CTs used in combined cycle applications are typically more efficient than "standalone" units and would have higher capacity prices, greater land requirements, etc. Unless the developer was willing to forego the later opportunity to convert the unit to combined cycle operation, I believe that many of these higher costs would be incurred anyway. As a result, I chose a relatively low cost oil-

fired CT for my "pure peaking" capacity option.

Despite the fact that I consider this an unrealistic scenario, I did examine options where capacity prices were based on combustion turbine plant costs, less attendant fuel savings. I found (as one might expect) that increasing the market reliance on CTs could decrease capacity prices somewhat, but, at the cost of much higher market energy prices. My simulations relying on an oil-fired CT capacity mix increased the market value of PECO's plants by more than a billion dollars. A gas-fired CT mix would increase PECO's market value by hundreds of millions of dollars. Thus, any scenario that increases the amount of CT generation relative to my all combined cycle mix would increase, not decrease, PECO's generation market value.

I mentioned this during my meeting with the PECO and ICF representatives, but apparently the PECO witnesses chose to ignore these facts. Nor did they propound any data requests on this subject to clarify it. In the end, I find it interesting that PECO's witnesses criticize me for using the same methodology they themselves employed. Finally, in nearly 20 years of performing marginal cost analyses, this is the first time I can recall anyone suggesting that marginal capacity costs should be computed assuming pure peaking plants would be built for fuel savings.

PLANT RELIABILITY

Q. Do you have any comments regarding the suggestion made by Mr. Rose and other PECO witnesses that you should have assumed higher combined cycle plant availabilities?

A. Once again, the PECO witnesses seem to prefer the use of hypothetical data for hypothetical new units, but provide no actual statistical data in support of their claims. In fact, the little actual information available suggests that there been reliability concerns with new combined cycle and combustion turbine plants. The August 12, 1996 Electric Utility Week presented an article that discusses serious problems with advanced combined-cycle and combustion turbine units that have become a major concern with owners, investors and insurers. This article is attached as Exhibit No.___(RJF-13).[12] According to this article, more than a half-dozen major failures are known and General Electric has indicated that some 70 of its machines (many not yet installed) required repair and overhaul in the past two years. The article further discusses plant explosions, litigation and increases in the cost of insurance and financing. Insurers are reported to have major concerns about the size and complexity of these newer turbines, and some insurers have left the market.

[12] This article has been reprinted with the permission of Electric Utility Week, a McGraw-Hill publication.

Q. Does this mean you lack confidence in new combined cycle or combustion turbine technology?

A. No. I expect that these types of problems will be resolved. However, I am quite skeptical about the extremely optimistic assumptions being made regarding the reliability, O&M costs, and maintenance requirements of these large and highly complex new machines. What I find to be truly interesting is the fact that the experts in this case have been quick to assume (or point out) the recently reported reductions in capital cost estimates for such plants, while ignoring the recent spate of reliability problems.

Q. Are there any statements contained in the article that have a direct bearing on the reasonableness of the PECO witnesses' availability assumptions?

A. Yes. The article indicates that within the financial community there are serious concerns about the practices that have been used by IPP's in operating combined cycle plants to increase availabilities. Recall that the higher availabilities for IPP plants were one of the major factors cited by the Dr. Venkateshwara in his support of the improved reliability of combined cycle plants. Quoting directly from the article:

"Scott Swensen of the Scudder Latin American Trust for Private Power and Pepe of Credit Lyonnais agreed that the new turbines have forced investors to scrutinize the technological

aspects of new power projects much more closely than in the past."

"**Beside their concerns about the technology**, many in the financial community believe IPPs in particular are pushing the envelope on operating practices to maintain a competitive edge."

"If a plant operator increases availability by increasing the firing temperature, it's a cause for concern," said Swensen. "To count on 97% availability is totally unrealistic."

"A representative of Deutsche Bank said, "When one of our consulting engineers tells us a plant is being operated according to standard 'IPP practice,' I say I don't know what that is. There's no track record for 'IPP practice' the way there is for 'utility practice'." (Emphasis in the original.)

Q. What availability (between maintenance outages) did the PECO witnesses assume in their studies for new combined cycle plants?

A. Mr. Bustard assumed 97% in his EDS study, Dr. Venkateshwara assumed 95% and Dr. Hieronymus assumed 95.4%. By way of comparison, the comparable availability rate I used was 88.7%, in line with the historical levels for utility owned combined cycle plants operated according to "standard utility practice."

REAL FIXED CHARGE RATES

Q. Mr. Rose criticizes your fixed charge rate calculation. Do you agree with him?

A. No. Once again, his criticism is unfounded and even amusing, considering that he admits the ICF calculation was incorrect in the first place. He criticizes the 3.1% inflation rate I used in my calculation, for example. Perhaps he should also file testimony criticizing Dr. Venkateshwara who used a 3% inflation rate and Mr. Bustard whose EDS study also used a 3% rate. My 3.1% rate was used to estimate the rate of inflation over the period 1995 to 2015, consistent with the EIA assumptions, and is the correct figure to use in the model because I started my projections from a 1995 base.

Mr. Rose is also being totally inconsistent in criticizing my calculation for not considering the lower initial rate of inflation projected by DRI and EIA. This is another double standard because none of the PECO witnesses who filed market price studies actually reflected the lower initial rate of inflation in their real fixed charge rate calculations either. Had any of us done so, we would have increased the initial level of the real fixed charge rate, thus increasing capacity values.

Q. Mr. Rose contends that his corrected real fixed charge rate, 12.7%, is identical to the original ICF calculation because two offsetting mistakes (exclusion of property and other taxes and an incorrect discount rate) have now been corrected. Do you agree?

A. No. Mr. Rose uses an after tax discount rate in computing the real fixed charge rate. The after tax discount rate was used by PECO in its computation of the market value methodology, and I endorse the PECO method. However, the PECO method computes a present value of *after tax* cash flows using an *after tax* discount rate. Mr. Rose computes the *gross of tax* cash flows for a new generator *with an after* tax discount rate, a clearly erroneous procedure. Mr. Rose's new calculation is no closer to being correct than the original one presented by Dr. Venkateshwara.

Q. Did anything bother you about Mr. Rose's contention that the after tax discount rate should be used in the real fixed charge rate calculation?

A. Yes. If this is a mistake, then I am not alone in making it. Dr. Hieronymus used the straight cost of capital in his calculation of real fixed charge rates, as did Mr. Bustard. In fact, I have reviewed literally hundreds of these types of calculations over the past 19 years. I also provided training to utilities in the calculation of fixed charge rates and revenue requirements when I worked at EMA. I have never seen one single case where a utility used the after tax discount rate to compute a levelized fixed charge rate (real or nominal). If there is anything approaching "standard utility practice" in this area, Mr. Rose's calculation is not it. Is it possible that the entire utility industry has incorrectly computed fixed charge rates? I don't

think so.

With just a little thought we can see why Mr. Rose's new calculation is simply wrong. Imagine computing the annual interest payment for a mortgage loan. This is the "home version" of the utility industry fixed charge rate calculation. Assuming a 10% interest rate for 23 years (the assumed life of a combined cycle plant), the annual mortgage rate would be 11.257%. For example, an annual payment of $11,257 present valued at 10% would recover 100,000. Any $10 calculator can be used to perform such a calculation.

To test the reasonableness of Mr. Rose's calculation I recreated his model and assumptions as is shown on Exhibit No.____(RJF-14). Next, I tested his formula by eliminating any factors that would not be present in a normal mortgage situation. I changed the debt interest rate to 10%, used 100% debt financing, eliminated property taxes, and removed accelerated tax depreciation. Finally, I set inflation to 0%. Under these assumptions, the calculation of the levelized real (and nominal) fixed charge rates under my "standard utility practice" method is 11.257%, identical to the mortgage formula result. Mr. Rose's methodology results in a fixed charge rate (his preferred mortgage payment) of 10.6%.[13] The reason is that

[13] If Mr. Rose still believes his calculation is correct, I would like for him to go to a bank with me and help me negotiate a mortgage. His approach would relieve borrowers of a substantial portion of their mortgage payments.

Mr. Rose has used the wrong discount rate and overstated the present value of future payments. This result is shown in Exhibit No.___(RJF-15). This is really interesting because Mr. Rose already admitted that the discount rate used in Dr. Venkateshwara's original calculation was wrong. His new discount rate is also wrong. As a result, the revised ICF study (as well as the original) is in error by hundreds of millions of dollars.[14]

Q. Do you have any comments about Mr. Rose's criticism that you should have used a 15 year tax life for new generators?

A. Some of this property will be in the 15 year asset class. However, other types of property (such as control buildings) have much longer tax lives. In addition, financing costs are deductible only over the life of the financing instruments. I believe twenty years is a reasonable composite life. Once again, I am being criticized for making the same assumptions as PECO's other witnesses. Dr. Hieronymus used a 20-year life assumption, for example. However, in this case, the criticism is moot. Correcting Mr. Rose's discount

[14] Note that for the ICF model this error goes well beyond its impact on capacity prices. The reason is that it will raise the cost of combined cycle plants relative to combustion turbines. Dr. Venkateshwara already testified that while his capacity mix was mostly combined cycle plants, there were no additional fuel savings relative to combustion turbine plants. Thus, this increase in the margin between CC and CT plants will by necessity require a re-optimization of the entire ICF expansion plan, resulting in the addition of more CTs and an increase in both market capacity and market energy prices.

rate alone results in a real fixed charge rate using his assumptions of 13.38%. [See Exhibit No.____(RJF-14).] This is virtually identical to my result of 13.34%. I see no reason to change my calculation at this time.

Q. Do you believe Dr. Hieronymus made a valid choice in accepting OCA witness Smith's figure?

A. No. I requested Mr. Smith's computation of the real fixed charge rate. He informed me that he did not have a specific calculation of this figure, and indicated it was based on a rather informal analysis. On this basis, I fail to see how Mr. Hieronymus can determine whether his assumptions are consistent with Mr. Smith's.

Q. Do you have any final comments regarding the real fixed charge rate calculation?

A. This is one of the most basic and important inputs to this analysis. All three of the PECO witnesses have admitted at some point that they miscalculated this basic input. The mistake in the EDS study was admitted in the QRO, Dr. Hieronymus has finally admitted to the error in his analysis, and Mr. Rose admits that Dr. Venkateshwara's figure was computed incorrectly. I have now demonstrated that Mr. Rose's new calculation is also wrong. In

every single case the PECO experts have understated this basic input! I stand by my original 13.34% calculation. My own calculation of 13.34% is supported by a reasonable, documented calculation, and, aside from the erroneous or irrelevant statements made by Mr. Rose, stands unchallenged.

REASONABLENESS OF MARKET ENERGY PRICE RESULTS

Q. Do you have any comments regarding Mr. Bustard's Exhibit No.___(JFB-18)?

A. Mr. Bustard's Exhibit No.___(JFB-18) demonstrates how unreasonable PECO's forecasts really are compared to historical data and my forecast. Mr. Bustard claims the reverse is true, suggesting that the historical decline in PJM market energy prices demonstrates the reasonableness of PECO's results.

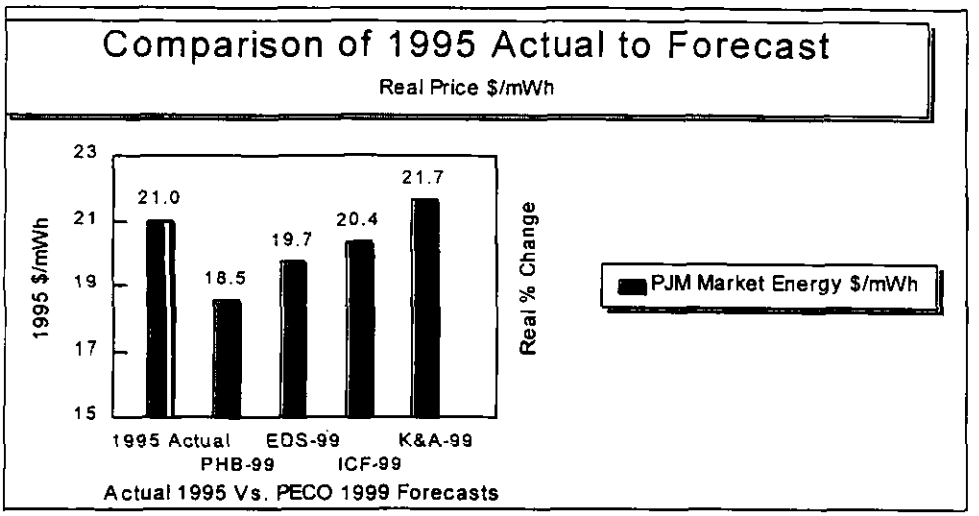
Q. Does Mr. Bustard have a valid point?

A. No. The historical decline in PJM energy prices shown in Exhibit No.___(JFB-18) is a direct consequence of the *decrease* in fuel prices in recent years and the addition of large new units such as Limerick 2, and substantial NUG capacity. Exhibit No.___(JFB-12) shows that

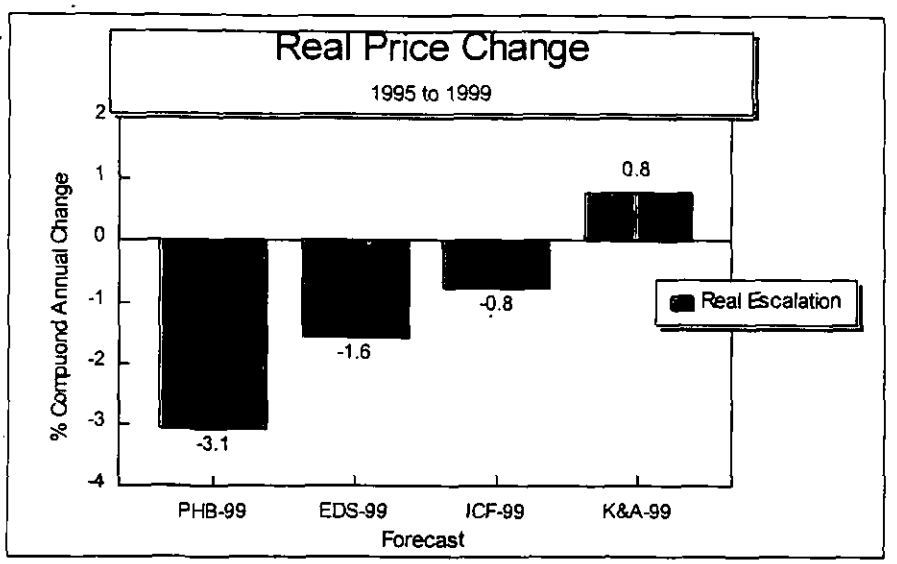
prices for coal, gas and oil have all dropped since 1990. As a result, the PJM market energy price dropped from $26/mWh in 1990 to $21/mWh in 1995. The problem with Mr. Bustard's analysis is that PECO's forecasts all assume fuel prices will *increase* in the years ahead. For this reason, Mr. Bustard's observation is irrelevant, at best. However, comparison of the projected PJM market energy prices in the PECO forecasts, with the fuel price forecast and the historic data, demonstrates serious anomalies in PECO's results. For example, all fuel prices are expected to *increase* from 1995 to 1999. Yet, Dr. Hieronymus' forecasts a *decrease* in market energy prices. In addition, ICF and EDS project a price decline in real terms. This is quite unreasonable given that most fuel price prices are expected to increase in PECO's forecast and PJM reserve margins are expected to decline over the period 1995 to 1999.

The comparison of the 1999 all hours market energy prices for the various PECO models to the 1995 actual is quite revealing. Considering that DRI forecasts an 8.6% increase in coal prices (from 1995 to 1999), a 13.5% increase in gas prices, a 10% increase in residual oil prices and a 16.5% increase for distillate oil prices, one would expect that the PJM energy rate would increase substantially over this period. Given that most of these fuels increase at a rate greater than inflation, one would expect a real rate of increase. This is particularly true considering that reserve margins are expected to decline from 1995 to 1999 and no

major new plants are being added.



However, the PHB analysis shows both a real and nominal drop in market energy prices from $21/mWh in 1995 (actual) to $20.2/mWh (PHB 1999 projected). EDS predicts only a 2.4% increase ($21.5/mWh in 1999 vs. $21.0/mWh for 1995). ICF predicts the largest price increase, an anemic 5.7% ($22.2/mWh in 1999). None of the three models even predicts growth in market prices equal to the *lowest* fuel price escalation rate. The PECO DRI forecast predicts a 9% increase in the GNP deflator from 1995 to 1999, a level substantially greater than PECO's projected market prices changes.



By comparison, the modeling I performed predicts an increase of 13.8%, a rate close to the amount of inflation over the period 1995 to 1999 (10.4% in the EIA forecast) and the underlying increase in fuel prices. Given the substantial decline in PJM reserve margins over the period and my assumption that bidding methods will change to reflect all incremental costs, the modest .8% annual real increase in market energy prices that I project is far more reasonable than the substantial real (and even nominal) decreases in prices projected by the PECO models (-3.1% per annum for PHB, -1.8% for EDS and -.8 % for ICF). The PECO forecasts do not make sense relative to historical data, given the increasing fuel prices the Company is using. PECO's forecasts do not pass the "sanity" test suggested by the very data Mr. Bustard has now provided.

Q. Does analysis of the data in Exhibit No.___(JFB-18) provide any additional insights?

A. Yes. Exhibit No.____(JFB-18) also provides a historical data point to benchmark the models against. I used historical 1995 fuel prices as the base year for my modeling. The PJM average historical billing rate averaged $21.0/mWh. For the 1995 base year my model predicted a PJM all hours energy rate of $20.22/mWh. While the assumptions used in my modeling (such as exclusion of variable O&M and a market based rather than incremental cost constrained bidding concept) differ from those used in PJM in 1995, the fact that my market energy price is so close to the actual data point demonstrates the reasonable nature of my forecast, modeling techniques and assumptions.

Q. Do longer term comparisons also provide additional insights?

A. Over the longer term the market energy prices are driven by the choice of capacity additions as well as fuel prices. The integrity of the models are more accurately tested by short term comparisons such as discussed above. However, longer term comparisons are useful in examining the underlying consistency of the assumptions driving the forecasts. My 2015 market energy price forecast is actually lower than any of the PECO models, due to my use of the lower EIA fuel price forecast and the all combined cycle expansion plan. Over the

period 1995 to 2015, I project a modest 3.5% growth rate for market energy prices. Given underlying inflation of 3.1% (and a 3.5% escalation rate for gas and 3.9% for oil) and a major shift in the generation mix as PJM's excess of baseload coal generation is exhausted, my projections are quite reasonable.

OTHER ISSUES

Q. Do you have any comments regarding Mr. Bustard's criticism of your discount rate?

A. Mr. Bustard has missed the mark again. The 7.6% discount rate was selected because it was consistent with the findings of the Commission in the securitization docket. In that case, the Commission accepted my calculation of stranded cost, which relied on a 7.74% discount rate. The Commission order also stated that it considered a discount rate of 7.5% appropriate for other purposes in that proceeding. I see no evidence to suggest that interest rates have increased by 100 basis points in the past few months. I believe the 7.6% is consistent with the Commission's thinking on discount rates and I continue to use it. PECO's adoption of Mr. Brennan's latest figures does demonstrate the ephemeral nature of PECO's increasingly result oriented assumptions. While PECO's April discount rate (8.41%) moved closer to the figure adopted in the Commission Order in the QRO and my recommended figure, PECO

has now moved further in the opposite direction. PECO now endorses a discount rate nearly the same as the one that the Commission already rejected in the prior proceeding, just a few months ago.

Q. Do you agree with Mr. Bustard's view that your market value estimate is overstated due to the so called "marginal units"?

A. No. In his rebuttal testimony on page 20 Mr. Bustard claims that my estimate of the market value for certain of the gas and oil units (Cromby 2, Eddystone 3 and 4, Delaware 7 and 8, and Schuylkill 1) is overstated by at least $482 million. However, he provides no support for his adjustment to my figures, other than his opinion that they are "too high". In other words, it appears that Mr. Bustard recommends excluding these plants from the market value calculation simply because he doesn't *like* the results.

Q. Could you explain why these "marginal" units are valued at a higher level in your model than in the PECO models?

A. Yes. For the most part these units don't even run in the PECO models and in most cases are assumed to be retired in 1999 or even before. However, prior to this proceeding PECO had

no plans to retire any of these plants (at least none reported to MAAC, the NERC, or the EIA). Mr. Bustard's testimony makes no claim that these units are unable to run any longer. Thus, I believe PECO admits that these hypothetical retirements were based on economic considerations, largely because of low market prices and lack of need for their energy. Because I project higher capacity prices, these plants are economic life extension candidates. Also, unlike the erroneous PECO models, my models project such plants will continue to run at around the same level as in 1995, generating some energy profits as well. PECO's "simplistic and therefore inexact" modeling of such plants grossly understates their value, as demonstrated by the fact that in Mr. Bustard's PMDAM model Eddystone 3 and 4 never run in the next 20 years, even though he assumes these units are available throughout the entire period. Mr. Bustard has never yet explained why his model doesn't show this plant operating over his forecast period. Considering that these units ran for thousands of hours in 1995, Mr. Bustard's results lack credibility.

Q. Do you have any observations concerning the updated ICF forecast that relies on the DRI fuel prices?

A. This analysis demonstrates one significant point. I have maintained all along that, using the same fuel price forecast, ICF would produce higher market prices than the PHB model. This

was confirmed by the ICF results. Using the same DRI fuel forecast, ICF predicts a market value $355 million higher than PHB. This demonstrates the validity of some of my earlier criticisms of the PHB models.

In addition, it is important to realize that this new ICF-DRI sensitivity case referenced by Mr. Rose is *not* the ICF forecast of market prices. The ICF market price forecast is still the one presented in Dr. Venkateshwara's testimony and, to my knowledge, it remains unchanged.

Q. Does this mean you now agree with the original ICF forecast?

A. No. I still disagree with certain assumptions, most notably prices for new combined cycle capacity and energy. These are differences in assumptions and reasonable analysts will differ.

However, the ICF forecast presented by Dr. Venkateshwara still contains a number of errors and omissions. For example, Mr. Rose's testimony acknowledges that the ICF real fixed charge rate was calculated incorrectly. It is instructive to examine these errors in order to understand how the ICF study compares to my own results.

Q. Please discuss the corrections to the ICF errors.

A. Dr. Venkateshwara computed a market value of $3.49 billion. This seems rather far from my own $4.81 billion result, but in reality is quite close to it once a few mandatory corrections are made to the ICF study. I start with the erroneous real fixed charge rate calculation that even Mr. Rose admits is wrong. Mr. Rose attempted to correct this calculation, but his lack of understanding of the rudimentary aspects of computing fixed charge rates led to an equally serious mistake in his "correction."

When I correct only Mr. Rose's erroneous discount rate assumption (the one that would help him escape from a large portion of his mortgage payments), but retain all other ICF assumptions, the result is 13.38%, only 4 basis points above my 13.34%. This produces an increase in market value of $195 million and narrows the gap between the PAIEUG and ICF results from $1.32 billion to $1.13 billion. As noted previously, this probably understates the correction because ICF would also need to re-optimize its capacity expansion plan.

The next mandatory adjustment is to reflect capital addition costs for new CTs. These were estimated to be $1.06/kW in 1993$ by Georgia Power in a certification proceeding for a new CT. ICF cited the GPC figures as support for its own CT assumptions. However, ICF

overlooked this information in computing its own cost of peaking capacity. Mr. Hill also included a virtually identical level of capital addition costs for PECO's CTs in his calculation of stranded costs. It is totally unexplained why all three PECO witnesses would ignore such costs for competitive generators, while Mr. Hill (and PECO's own supporting documents) includes them for PECO's CTs. Inclusion of the capital additions for combustion turbines increases the ICF forecast by another $102 million, and narrow the differential between the ICF and PAIEUG studies from $1.13 billion to $1.03 billion.

Almost identical comments apply in the case of A&G expenses for new peaking units. If nothing else, CTs will require accountants to do their books, purchasing agents to buy fuel, and maintenance personnel to perform repairs. All of these employees will have pensions, health insurance and require a Personnel Department. Competitors' CTs will require most of the same support functions as any generator would incur. PECO has included such costs for its own generators (once again including PECO's own CTs) but has ignored these costs for potential competitors. What is really interesting is that PECO seized upon Mr. Baron's recommendation to increase the A&G assigned to production, but did not do so when it came to new CTs. This required adjustment would increase the market value in Dr. Venkateshwara's testimony by $239 million. This reduced the differential between studies from $1.03 billion to $788 million.

Next, I would substitute the PECO discount rate, and use the 7.6%, which is consistent with the Commission's QRO order. This increases the ICF market value by $428 million and narrows the difference between our studies to $360 million.

Another critical adjustment is needed to reflect the fact that PECO incorrectly discounted all cash flows from generators to year end. PECO assumed it would not receive a penny in revenue from its plants until the last day of the year. To account for the fact that both expenses and revenues will flow throughout the year, I increase the NPV calculations by one half of a year's discount rate. This adjustment increases market value by $215 million. This narrows the difference between ICF and PAIEUG to $145 million.

The next adjustments is to remove fossil decommissioning costs. As discussed by Mr. Kollen, the Commission has not historically allowed these type of costs under regulation, and they are hardly known and measurable. We also must correct the mistake in PECO's nuclear decommissioning costs as further discussed by Mr. Kollen. This increases the market value by $73 million. With this adjustment the ICF model result would increase to $4.74 billion, only $72 million less than the PAIEUG result of $4.81 billion. Naturally, differences do remain. ICF projects higher fuel prices, while I project higher capital costs for new combined cycle plants. I use a probabilistic model, while ICF uses a deterministic model.

Q. Does this mean you would now recommend use of the "corrected" ICF model?

A. No. I believe my assumptions are more realistic than ICF's and that my modeling results are more logical. However, this analysis demonstrates that PECO has produced nothing of substance in its criticisms of my model and that the Commission can consider that the ICF and EIA fuel price forecasts both support a market value of $4.8 billion, once some erroneous assumptions made by ICF are corrected, and costs are treated equally between PECO's generators and the new resources in the marketplace.

Q. Are you making any adjustments to your original stranded cost estimates?

A. As discussed above, we accept PECO's increase of the A&G allocation to production. I have also adopted these updates for my study, and as a result would decrease my market value to $4.54 billion and increase stranded cost to $2.14 billion. These results are summarized in Exhibit No.___(RJF-16).

Q. Does this conclude your testimony?

A. Yes.

PAIEUG STATEMENT NO. 2S

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	)	
v.	)	
PECO ENERGY COMPANY	)	
APPLICATION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	)	DOCKET NO. R-00973593

SURREBUTTAL

EXHIBITS

OF

RANDALL J. FALKENBERG

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

NOVEMBER 1997

Exhibit No.___(RJF-12)

Case 1: New Model

Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1	PECO CT's	Martin Cr.	PPL CT's
327.	562.	501.	129.	83.	86.	113.	769.	36.

Case 2 Exactly as Modeled In Original Direct Testimony Market Price Studies

Summer

Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1	PECO CT's	Martins Cr.	PPL CT's
176.	303.	290.	76.	53.	57.	83.	387.	27.

Spring, Fall, Winter

Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1	PECO CT'S	Martins Cr.	PPL CT's
189.	310.	290.	72.	44.	45.	59.	277.	20.

Total 1995 As Modeled

Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1	PECO CT'S	Martins Cr.	PPL CT's
365.	613.	580.	148.	97.	102.	142.	664.	47.

Comparison to Actual 1995

	Actual	CF	Case 1	CF	Case 2	CF	mW
Eddystone 3 & 4	1908.	28.7	1063.	16.0	1193.	17.9	760.
Cromby 2	746.	42.4	327.	18.6	365.	20.7	201.
Delaware 7 & 8	249.	11.4	212.	9.7	245.	11.2	250.
Schuylkill 1	159.	10.9	86.	5.9	102.	7.0	166.
PECO CT's	174.	2.4	113.	1.5	142.	1.9	835.
Martins Cr. 3 & 4	1033.	7.4	769	5.5	664.	4.8	1592.
PP&L CT's	23.	0.7	36.	1.0	47.	1.4	393.

PAIEUG STATEMENT NO. 2S

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	)	
v.	)	
PECO ENERGY COMPANY	)	
	)	DOCKET NO. R-00973593
APPLICATION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	)	

SURREBUTTAL

EXHIBIT No.____(RJF-13)
Pages 1-3

OF

RANDALL J. FALKENBERG

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

NOVEMBER 1997

ELECTRIC UTILITY WEEK

A Publication of The McGraw-Hill Companies

August 12, 1996

PROBLEMS WITH NEW TURBINES WORRY PLANT OWNERS, BANKS AND INSURERS

Problems with advanced combined-cycle turbines, widely used for new gas-fired independent power and utility plants, have become a major concern among owners, investors and insurers.

More than a half-dozen major failures are known and General Electric said about 70 of its F series machines—most not yet installed—required repair and overhaul over the past two years.

The first major reported incident was last year's explosion of a Siemens 84.2 gas turbine at Diamond Energy's 663-MW Doswell power plant, which cost the independent between $50-million and $72-million in lost revenue from power sales to Virginia Power (EUW, 27 Feb '95, 2).

Other incidents followed, such as the failure in January of seven ABB GT11N turbines at CMS Generation's 1,370-MW Midland Cogeneration plant, which sells power to affiliate Consumers Power. Also, on the eve of commercial operation this spring, two GE 9FA machines at the 660-MW AES Medway plant in the U.K. had to be removed and repaired.

Meanwhile, Destec Energy is in litigation with GE regarding fixes to its 7FA turbine at Destec's 212-MW Tiger Bay plant in Florida.

Utilities have suffered as well, including failures at Virginia Power's Chesterfield station, Delmarva Power & Light's Hay Road plant and Kentucky Utilities' E.W. Brown station.

About 86 turbines installed since 1990 involve models

(continued on page 18)

PROBLEMS WITH NEW TURBINES WORRY INDUSTRY...begins on page 1

that have experienced failures at other sites, according to a joint report by The McGraw-Hill Companies' *Power* magazine, based in New York, and the *Utility Data Institute*, Washington, D.C.

"The whole world has changed," AES senior vice president Kenneth Woodcock said in an interview. "Ten years ago, equipment would have been forced by a public utilities commission to get full testing before it was allowed to go into a utility's rate base. Now, that equipment risk is being taken by electricity suppliers—that is, us—who are under pressure to rush to market to hang onto market share."

Until recently, the industry was impressed by the new turbines' upside potential: efficiency levels approaching 60%, doubled capacity, the potential to consistently achieve 90%-plus availability, compliance with strict air quality standards, and power plant capital cost reductions of 30% to 40% (EUW, 26 Feb, 16).

But the industry glossed over the likelihood that the sophisticated and complicated machines, adapted from the military aircraft industry and costing as much as $30-million each, could have design flaws and suffer performance failures.

"Before the new models came along, we took turbines for granted," said Michael Pepe of Credit Lyonnais' project finance group. "Now our work is a lot harder, in terms of the amount of due diligence we and our insurance and engineering consultants have to do on the turbines themselves. We spend as much time now on the gas turbine aspect of a new project as on any other part of a deal."

The consensus is that GE's F series machines have been the least reliable and that Westinghouse, by being slower to market with its large turbines, has experienced the fewest serious problems. Yet all the major manufacturers remain publicly bullish about their equipment.

Although some people interviewed spoke reluctantly and without attribution, most are ready for a full exchange of information about a subject that has been mostly discussed behind closed doors, for instance, in manufacturer-sponsored user group meetings with irate owners, meetings from which the financial community has been excluded.

One sign of greater openness was the conference sponsored last Tuesday by the Gas Turbine Institute on the insurability of the new machines.

While insurance and financing will remain available, albeit at a high price, to owners of projects that employ new-model turbines, many people insist that new cost-sharing and risk-sharing arrangements are necessary to ease the current crisis of confidence, participants noted.

Financial consequences of turbine failures are high. Replacing one cracked rotor blade can run about $2.5-million and power sales revenue losses can run $3-million per turbine per month, according to one insurer.

"Ours is an evolutionary, not revolutionary, design," said Steve Kuehm of Siemens Corp. Mike Asquino of Westinghouse Electric Corp. echoed this assertion.

Kuehm and Asquino touted their new computer modeling capability and said it adequately compensates for the absence of prototype testing. A GE spokesman, on the other hand, said there is no substitute for thousands of hours of field operations.

Although Kuehm said Siemens put one of its latest model V84.3A turbines on the factory test bed, in-house "hot testing" has become rare. "We can't test these machines in-house—they're too big and it would be prohibitively expensive," said Asquino of Westinghouse.

Insurers find this limitation unsettling and note that, after months or years of hard-driving operation in the field, unproven turbines can reach break-points that computers could never detect.

If the manufacturers' common refrain is "evolutionary design," insurers unanimously complain, "We are not in business to fund R&D." Doug Rode of the risk management consulting firm Capital Assets Management made this point, as did representatives of Chubb Insurance, Industrial Risk Insurers, and Deutsche Bank.

Yet R&D funding is exactly what insurers believe they have been forced to take on, by issuing coverage for a variety of new-model turbines without significant operating history that are installed in customized configurations. Insurers want between 8,000 and 20,000 hours of operating history before they consider a machine proven.

Insurers are nervous about not only the size—one insurer pointed out that a single advanced turbine can produce enough gross power output to propel a nuclear aircraft carrier at top speed—but also the sheer technical complexity of the new machines.

"There's a maximum size, based on the turbine's compressor blade tip speed," said Henry Tessier of Industrial Risk Insurers. "But now manufacturers are building multiple speed compressors—so who knows what their limits are?"

Scott Swensen of the Scudder Latin American Trust for Private Power and Pepe of Credit Lyonnais agreed that the new turbines have forced investors to scrutinize the technological aspects of new power projects much more closely than in the past.

Besides their concerns about the technology, many in the financial community believe IPPs in particular are pushing the envelope on operating practices to maintain a competitive edge.

"If a plant operator increases availability by increasing the firing temperature, it's cause for concern," said Swensen. "To count on 97% availability is totally unrealistic."

A representative of Deutsche Bank said, "When one of our consulting engineers tells us a plant is being operated according to standard 'IPP practice,' I say I don't know what that is. There's no track record for 'IPP practice' the way there is for 'utility practice'."

"Plant operators are under a lot of pressure," said Rode of Capital Assets Management. "If they're supposed to wait two hours before starting a plant up again, they may say, let's do it after one hour, to reduce down-time." He added that some developers plan to sell off their interest in a plant in a few years, in which case they may run the facility with an eye on short-term profit rather than long-term viability.

"IPPs tend to be very, very frugal when it comes to maintenance, because every dollar they spend is a dollar out of the owners' pockets," another insurer said. "There are many cases where they keep deferring maintenance."

General Electric's product general manager for its combined-cycle turbines, Jack Callahan, said IPPs face short- and long-term financial pressures that pull them in two different directions simultaneously.

"IPPs want to be competitive over the long-term, so they have a tremendous desire to be the technological innovator" and acquire the latest technology, Callahan said. "Yet at the same time, because of financial operating pressures, they're trying to manage risks" in the short-term. He added that IPPs tend to have limited in-house technical expertise, which impacts their ability to manage the new technology.

Insurers also distrust the operator training systems for today's sophisticated machines. When a turbine is installed, the manufacturer trains the current power plant staff, but over several years, the original trainees move on and new employees are instructed by second- and third-generation operators. And quality-control at overseas plants can be much harder to maintain than in the U.S.

This array of risk factors has caused insurers to change their practices with regard to independent power. At the very least, they are limiting their coverage, raising their premiums or refusing to cover specific power plants.

Lenders require IPPs to obtain not only property damage insurance, as was the norm for regulated utilities, but also business interruption coverage.

"Primary insurers used to cover the first $5-million in liabilities and get reinsurance for the next tier," said Rode. "Now primary insurers cover only the first $1-million and get reinsurance beyond that."

Ominously, several insurers have withdrawn from the IPP market. It is widely known that Zurich America walked away from the sector in late-1994 or early-1995. Zurich had insured Diamond Energy's Doswell plant, although its decision to pull out of independent power may have preceded the explosion of the Siemens turbine last year. Zurich did not return calls seeking comment.

In the wake of Doswell, Industrial Risk Insurers has stopped covering IPPs, Tessier said. Travelers has stopped covering business interruption, which effectively means a pull-out from the IPP sector. Hartford Steam Boiler, Factory Mutual and Chubb Insurance are among those still offering coverage.

Peter Thompson of Chubb's Energy Resources Group said, "IPPs will be able to get insurance from us. But it will be based on how much risk we're willing to take on, and how much the manufacturers will assume" in the form of longer and stronger warranties.

Some manufacturers are balking at the prospect of greater risk-sharing, Thompson added. Manufacturers' warranties on their workmanship are typically for one year, and beyond that, IPPs are exposed to the risk of lost revenues from plant shut-downs.

Today's competitive, technology-driven landscape for private power is spurring demands for new arrangements for spreading the technology risk now largely borne by power plant owners. One proposal, pressed by power plant owners and insurers, is for manufacturers to extend their warranties to two and three years.

GE said it may offer customers some new kinds of O&M agreements and service packages to compensate for the new turbines' greater technological risks and for deficiencies in customers' technical expertise. "We're looking at an O&M agreement that would give customers more security about what their O&M costs will be over the long term, and would offer a level of guaranteed availability" for the turbine," said GE's Callahan.

"Insurers' concerns will die down in five years, once our machines have a lot of operating history," Siemens' Steve Kuehm predicts.

But in the meantime, "there must be some partnering relationship between manufacturers, IPPs and insurers," said Thompson of Chubb. "If there's a weak link in the relationship, it's not going to work."

Exhibit No.___(RJF-14)

INPUT PARAMETERS SUMMARY

Unit Size (mW)	1	Tax Life	20
On-line date	1	MACRS rate	0.00%
On-line month	1	Tax Depn Base/Book	100.00%
Book Life	23	Tax Rate	41.30%
Investment ($/kW)	100,000	Other Tax Rate	1.00%
Inflation	3.00%	% Of Year	100.00%
Cost of Debt	9.90%	Month PV Adj	100.00%
Percent Debt	50.00%	Investment ($ 000)	10,000
Cost of Equity	14.00%	Salvage (%)	0.00%
Percent Equity	50.00%	ITC Rate	0
Rate of Return	11.95%	ITC Amort	0.0
A& G Loading	0.00%	Salvage $	0
BOY =0, EOY =1, AVG =2	0	ITC Total	0

SUMMARY OF RESULTS

	PV RR	FCCR	ECCR
Rev Req (PV RR)	127515	18.4656%	13.38%
Cap Rec Factor	12.913%	16466	
Rate of Return	60971	7.87%	
FIT/SIT	25129	3.24%	
Book Depreciation	33871	4.35%	
Insurance	0	0.00%	
Property Taxes	7744	1.00%	
		16466	

Notes:
1. The 1% is only enough to cover the Prop. Taxes. In TPH-5, page 24 prop. Tax for CTS are about $2.84/kW year or about 1% of investment new plant.
2. Uses ICF conservative capital structure.

	Conventional Discount Rate ========ECCR======== REV. REQ.	RATE	PW FACTOR	PW REV REQ		ICF Discount Rate NPV Factor	NPV Rev. Requirmts	9.91% Inflation Factor	ICF Real FC 12.71% NPV		NPV
6						Total	142715		11	0	142715
	13381	13.38%	89.33%	11953	100	0.91	20220	1.00	0.91	12713	11567
	13783	13.78%	79.79%	22950	103	0.83	17753	1.03	0.85	13095	10841
	14196	14.20%	71.27%	33089	106	0.75	15329	1.06	0.80	13488	10160
	14622	14.62%	63.67%	42378	109	0.69	13244	1.09	0.75	13892	9521
	15061	15.06%	56.87%	50943	113	0.62	11447	1.13	0.70	14309	8923
	15513	15.51%	50.80%	58823	116	0.57	9897	1.16	0.66	14738	8362
	15978	15.98%	45.38%	66074	119	0.52	8559	1.19	0.62	15180	7837
	16457	16.46%	40.53%	72744	123	0.47	7392	1.23	0.58	15636	7344
	16951	16.95%	36.21%	78882	127	0.43	6366	1.27	0.54	16105	6883
	17460	17.46%	32.34%	84529	130	0.39	5464	1.30	0.51	16588	6451
	17984	17.98%	28.89%	89724	134	0.35	4674	1.34	0.48	17086	6045
	18523	18.52%	25.81%	94504	138	0.32	3982	1.38	0.45	17598	5665
	19079	19.08%	23.05%	98902	143	0.29	3376	1.43	0.42	18126	5309
	19651	19.65%	20.59%	102948	147	0.27	2847	1.47	0.39	18670	4976
	20241	20.24%	18.39%	106671	151	0.24	2386	1.51	0.37	19230	4663
	20848	20.85%	16.43%	110096	156	0.22	1985	1.56	0.34	19807	4370
	21473	21.47%	14.68%	113247	160	0.20	1679	1.60	0.32	20401	4096
	22117	22.12%	13.11%	116148	165	0.18	1449	1.65	0.30	21013	3838
	22781	22.78%	11.71%	118814	170	0.17	1247	1.70	0.28	21644	3597
	23464	23.46%	10.46%	121268	175	0.15	1089	1.75	0.27	22293	3371
	24168	24.17%	9.34%	123526	181	0.14	914	1.81	0.25	22962	3159
	24893	24.89%	8.35%	125604	186	0.13	777	1.86	0.23	23651	2961
	25640	25.64%	7.45%	127515	192	0.11	658	1.92	0.22	24360	2775
	0	0.00%	8.66%	127515	0	0.10	0	0.00	0.00	0	0

ANNUAL REVENUE REQUIREMENTS

	** RATE BASE ($MILL, BOY) ** G PL	ACCUM DEPR	ADFIT	BOY INVEST	APPLIED AVG. INVEST	BOOK DEPR	DEBT COST	EQUITY COST	** DEFERRED TAXES ** ACC TAX DEPR	SL TAX DEPR	DFIT	18.47% TAXABLE INCOME	41.30% CURRENT TAX	TOTAL TAX	Subtotal	Other Tax	A&G	PROP. TAX INSURANCE	TOTAL RR	PW FACTOR	PW REV REQ	NPV of REV REQ
1	***			100,000	100,000																	
2	***	4,348	269	95,383	95,383	4,348	4,950	7,000	5,000	4,348	269	11,273	4,656	4,925	21223	1,000	0	1000	22,223	0.8933	19,851	19,851
3	***	8,696	2,397	88,907	88,907	4,348	4,721	6,677	9,500	4,348	2,128	8,222	2,570	4,698	20444	1,000	0	1000	21,444	0.7979	17,110	36,961
4	***	13,043	4,133	82,824	82,824	4,348	4,100	5,798	7,700	4,348	1,384	6,525	2,695	4,079	18324	1,000	0	1000	20,351	0.7127	14,505	51,466
5	***	17,391	5,517	77,092	77,092	4,348	3,816	5,396	6,930	4,348	1,086	6,611	2,730	3,797	17357	1,000	0	1000	19,324	0.6367	12,303	63,769
6	***	21,739	6,584	71,677	71,677	4,348	3,548	5,017	6,230	4,348	777	6,865	2,753	3,530	16443	1,000	0	1000	18,357	0.5687	10,440	74,208
7	***	26,087	7,361	66,552	66,552	4,348	3,294	4,659	5,900	4,348	641	6,384	2,637	3,278	15579	1,000	0	1000	17,443	0.5080	8,861	83,069
8	***	30,435	8,002	61,563	61,563	4,348	3,047	4,309	5,900	4,348	641	5,789	2,391	3,032	14737	1,000	0	1000	16,579	0.4538	7,523	90,592
9	***	34,783	8,643	56,574	56,574	4,348	2,800	3,960	5,910	4,348	645	5,184	2,141	2,786	13895	1,000	0	1000	15,737	0.4053	6,379	96,970
10	***	39,130	9,288	51,581	51,581	4,348	2,553	3,611	5,900	4,348	641	4,599	1,899	2,540	13052	1,000	0	1000	14,895	0.3621	5,393	102,363
11	***	43,478	9,929	46,593	46,593	4,348	2,306	3,261	5,910	4,348	645	3,994	1,650	2,295	12210	1,000	0	1000	13,210	0.2889	3,816	110,724
12	***	47,826	10,574	41,599	41,599	4,348	2,059	2,912	5,900	4,348	641	3,409	1,408	2,049	11368	1,000	0	1000	12,368	0.2581	3,192	113,916
13	***	52,174	11,215	36,611	36,611	4,348	1,812	2,563	5,910	4,348	645	2,804	1,158	1,803	10526	1,000	0	1000	11,526	0.2305	2,657	116,573
14	***	56,522	11,861	31,618	31,618	4,348	1,565	2,213	5,900	4,348	641	2,218	916	1,557	9583	1,000	0	1000	10,683	0.2059	2,200	118,772
15	***	60,870	12,502	26,629	26,629	4,348	1,318	1,864	5,910	4,348	645	1,613	666	1,311	8641	1,000	0	1000	9,899	0.1839	1,819	120,593
16	***	65,217	13,147	21,636	21,636	4,348	1,071	1,515	2,950	4,348	(577)	3,978	1,643	1,066	7999	1,000	0	1000	8,999	0.1643	1,478	122,061
17	***	69,565	12,570	17,865	17,865	4,348	884	1,251	0	4,348	(1,796)	6,478	2,676	880	7363	1,000	0	1000	8,363	0.1468	1,227	123,288
18	***	73,913	10,774	15,313	15,313	4,348	758	1,072	0	4,348	(1,796)	6,174	2,550	754	6932	1,000	0	1000	7,932	0.1311	1,040	124,328
19	***	78,261	8,978	12,761	12,761	4,348	632	893	0	4,348	(1,796)	5,870	2,424	628	6501	1,000	0	1000	7,501	0.1171	878	125,206
20	***	82,609	7,183	10,209	10,209	4,348	505	715	0	4,348	(1,796)	5,565	2,298	503	6071	1,000	0	1000	7,071	0.1048	740	125,946
21	***	86,957	5,387	7,657	7,657	4,348	379	536	0	4,348	(1,796)	5,261	2,173	377	5640	1,000	0	1000	6,640	0.0934	620	126,566
22	***	91,304	3,591	5,104	5,104	4,348	253	357	0	4,348	(1,796)	4,957	2,047	251	5209	1,000	0	1000	6,209	0.0835	518	127,084
23	***	95,652	1,796	2,552	2,552	4,348	126	179	0	4,348	(1,796)	4,652	1,921	126	4779	1,000	0	1000	5,779	0.0745	431	127,515
24	***	100,000	(0)	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0666	0	127,515

Exhibit No.___(RJF-16)

INPUT PARAMETERS SUMMARY

Unit Size (mW)	1	Tax Life	20
On-line date	1	MACRS rate	0.00%
On line month	1	Tax Depn Base/Book	100.00%
Book Life	23	Tax Rate	41.30%
Investment ($/kW)	100,000	Other Tax Rate	0.00%
Inflation	0.00%	% Of Year	100.00%
Cost of Debt	10.00%	Month PV Adj	100.00%
Percent Debt	100.00%	Investment ($ 000)	10,000
Cost of Equity	0.00%	Salvage (%)	0.00%
Percent Equity	0.00%	ITC Rate	0
Rate of Return	10.00%	ITC Amort	0.0
A& G Loading	0.00%	Salvage $	0
BOY =0, EOY =1, AVG =2	0	ITC Total	0

SUMMARY OF RESULTS

	PV RR	FCCR	ECCR
Rev Req (PV RR)	100000	11.2572%	11.26%
Cap Rec. Factor	11.257%	11257	
Rate of Return	61377	6.91%	
FIT/SIT	0	0.00%	
Book Depreciation	38623	4.35%	
Insurance	0	0.00%	
Property Taxes	0	0.00%	
		11257	

Conventional Discount Rate 10.00%

6	=======ECCR====== REV. REQ.	RATE	PW FACTOR	PW REV REQ
	11257	11.26%	90.91%	10234
	11257	11.26%	82.64%	19537
	11257	11.26%	75.13%	27995
	11257	11.26%	68.30%	35684
	11257	11.26%	62.09%	42674
	11257	11.26%	56.45%	49026
	11257	11.26%	51.32%	54805
	11257	11.26%	46.65%	60058
	11257	11.26%	42.41%	64830
	11257	11.26%	38.55%	69171
	11257	11.26%	35.05%	73116
	11257	11.26%	31.86%	76703
	11257	11.26%	28.97%	79964
	11257	11.26%	26.33%	82928
	11257	11.26%	23.94%	85623
	11257	11.26%	21.76%	88073
	11257	11.26%	19.78%	90300
	11257	11.26%	17.99%	92325
	11257	11.26%	16.35%	94185
	11257	11.26%	14.86%	95839
	11257	11.26%	13.51%	97360
	11257	11.26%	12.28%	98743
	11257	11.26%	11.17%	100000
	0	0.00%	10.15%	100000

ICF Discount Rate 5.87% ICF Real FC 10.63%

	NPV Factor Total	NPV Rev. Requirmts	Inflation Factor	NPV 12	NPV 0	NPV 132278
100	0.94	13552	1.00	0.94	10626	10037
100	0.89	12413	1.00	0.89	10626	9461
100	0.84	11358	1.00	0.84	10626	8955
100	0.80	10382	1.00	0.80	10626	8458
100	0.75	9480	1.00	0.75	10626	7989
100	0.71	8646	1.00	0.71	10626	7546
100	0.67	7875	1.00	0.67	10626	7128
100	0.63	7162	1.00	0.63	10626	6733
100	0.60	6505	1.00	0.60	10626	6360
100	0.57	5899	1.00	0.57	10626	6007
100	0.53	5339	1.00	0.53	10626	5674
100	0.50	4824	1.00	0.50	10626	5359
100	0.48	4350	1.00	0.48	10626	5062
100	0.45	3913	1.00	0.45	10626	4781
100	0.43	3511	1.00	0.43	10626	4516
100	0.40	3142	1.00	0.40	10626	4266
100	0.38	2803	1.00	0.38	10626	4029
100	0.36	2492	1.00	0.36	10626	3806
100	0.34	2206	1.00	0.34	10626	3595
100	0.32	1945	1.00	0.32	10626	3396
100	0.30	1706	1.00	0.30	10626	3207
100	0.29	1487	1.00	0.29	10626	3030
100	0.27	1288	1.00	0.27	10626	2862
0	0.25	0	0.00	0.00	0	0

Notes:
1. The 1% is only enough to cover the Prop Taxes. In TPH-5, page 24 prop. Tax for CTS are about $2.84/kW year or about 1% of investment new plant.
2. Uses ICF conservative capital structure.

ANNUAL REVENUE REQUIREMENTS

G PL	** RATE BASE ($MILL, BOY) ** ACCUM DEPR	ADFIT	BOY INVEST	APPLIED AVG. INVEST	BOOK DEPR	DEBT COST	EQUITY COST	** DEFERRED TAXES ** ACC TAX DEPR	SL TAX DEPR	DFIT	11.26% TAXABLE INCOME	41.30% CURRENT TAX	TOTAL TAX	Subtotal	Other Tax	A&G	PROP. TAX INSURANCE	TOTAL RR	PW FACTOR	PW REV REQ	NPV of REV REQ
1 ***			100,000	100,000	4,348	10,000	0	4,348	4,348	0	0	0	0	14348	0	0	0	14,348	0.9091	13,043	13,043
2 ***	4,348	0	95,652	95,652	4,348	9,565	0	4,348	4,348	0	0	0	0	13913	0	0	0	13,913	0.8264	11,498	24,542
3 ***	8,696	0	91,304	91,304	4,348	9,130	0	4,348	4,348	0	0	0	0	13478	0	0	0	13,478	0.7513	10,126	34,668
4 ***	13,043	0	86,957	86,957	4,348	8,696	0	4,348	4,348	0	0	0	0	13043	0	0	0	13,043	0.6830	8,909	43,577
5 ***	17,391	0	82,609	82,609	4,348	8,261	0	4,348	4,348	0	0	0	0	12609	0	0	0	12,609	0.6209	7,829	51,406
6 ***	21,739	0	78,261	78,261	4,348	7,826	0	4,348	4,348	0	0	0	0	12174	0	0	0	12,174	0.5645	6,872	58,278
7 ***	26,087	0	73,913	73,913	4,348	7,391	0	4,348	4,348	0	0	0	0	11739	0	0	0	11,739	0.5132	6,024	64,302
8 ***	30,435	0	69,565	69,565	4,348	6,957	0	4,348	4,348	0	0	0	0	11304	0	0	0	11,304	0.4665	5,274	69,576
9 ***	34,783	0	65,217	65,217	4,348	6,522	0	4,348	4,348	0	0	0	0	10870	0	0	0	10,870	0.4241	4,610	74,185
10 ***	39,130	0	60,870	60,870	4,348	6,087	0	4,348	4,348	0	0	0	0	10435	0	0	0	10,435	0.3855	4,023	78,208
11 ***	43,478	0	56,522	56,522	4,348	5,652	0	4,348	4,348	0	0	0	0	10000	0	0	0	10,000	0.3505	3,505	81,713
12 ***	47,826	0	52,174	52,174	4,348	5,217	0	4,348	4,348	0	0	0	0	9565	0	0	0	9,565	0.3186	3,048	84,761
13 ***	52,174	0	47,826	47,826	4,348	4,783	0	4,348	4,348	0	0	0	0	9130	0	0	0	9,130	0.2897	2,645	87,406
14 ***	56,522	0	43,478	43,478	4,348	4,348	0	4,348	4,348	0	0	0	0	8696	0	0	0	8,696	0.2633	2,290	89,696
15 ***	60,870	0	39,130	39,130	4,348	3,913	0	4,348	4,348	0	0	0	0	8261	0	0	0	8,261	0.2394	1,978	91,673
16 ***	65,217	0	34,783	34,783	4,348	3,478	0	4,348	4,348	0	0	0	0	7826	0	0	0	7,826	0.2176	1,703	93,377
17 ***	69,565	0	30,435	30,435	4,348	3,043	0	4,348	4,348	0	0	0	0	7391	0	0	0	7,391	0.1978	1,462	94,839
18 ***	73,913	0	26,087	26,087	4,348	2,609	0	4,348	4,348	0	0	0	0	6957	0	0	0	6,957	0.1799	1,251	96,090
19 ***	78,261	0	21,739	21,739	4,348	2,174	0	4,348	4,348	0	0	0	0	6522	0	0	0	6,522	0.1635	1,066	97,156
20 ***	82,609	0	17,391	17,391	4,348	1,739	0	4,348	4,348	0	0	0	0	6087	0	0	0	6,087	0.1486	905	98,061
21 ***	86,957	0	13,043	13,043	4,348	1,304	0	4,348	4,348	0	0	0	0	5652	0	0	0	5,652	0.1351	764	98,825
22 ***	91,304	0	8,696	8,696	4,348	870	0	4,348	4,348	0	0	0	0	5217	0	0	0	5,217	0.1228	641	99,466
23 ***	95,652	0	4,348	4,348	4,348	435	0	4,348	4,348	0	0	0	0	4783	0	0	0	4,783	0.1117	534	100,000
24 ***	100,000	0	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1015	0	100,000

Exhibit No. ___(RJF-16a)
TOTAL STRANDED COST CALCULATION

Net Present Value of Contribution Margins	$3,305,937
Inventory and Working Capital Carrying Charges	($171,484)
Future Tax Depreciation Benefits	$330,886
Accumulated Deferred Investment Tax Credit Benefits	$151,590
Deferred Income Tax	$927,392
Total Adjusted NPV	$4,544,321
Book Value	$6,688,384
Stranded Generation Cost	$2,144,063

Scenario: EIA FUEL PRICE Escalation, Modified A&G Allocation

Exhibit No.___(RJF-16b)
CALCULATION OF NET PRESENT VALUE OF CONTRIBUTION MARGINS

		==========Capacity==========				Capacity	Capacity	Energy	PSH								Net
	Year	Large Units	CT's	PSH	Total	Charges	Revenue	Margins	Margins	Total Costs	O&M	Cap. Add	A&G	Other Tax	Decomm.	Life Ext.	Margin
	1999	7462	835	880	9177	24.71	$226,774	$687,118	$8,891	$865,989	$505,885	$95,311	$82,031	$87,573	$26,425	$68,764	$56,794
	2000	7462	835	880	9177	31.66	$290,506	$769,598	$11,167	$812,320	$519,201	$97,684	$81,437	$87,573	$26,425	$0	$258,950
	2001	7462	835	880	9177	47.64	$437,217	$774,134	$11,364	$831,970	$533,739	$100,615	$83,619	$87,573	$26,425	$0	$390,745
	2002	7462	835	880	9177	50.23	$460,946	$799,620	$11,839	$852,830	$548,672	$103,633	$86,527	$87,573	$26,425	$0	$419,574
	2003	7462	835	880	9177	54.65	$501,491	$813,077	$12,807	$969,685	$571,987	$108,742	$88,709	$87,573	$26,425	$88,230	$357,710
	2004	7462	835	880	9177	59.42	$545,285	$818,383	$12,021	$937,037	$589,582	$109,944	$91,617	$87,573	$26,425	$31,895	$438,653
Disc. Rate	2005	7462	835	880	9177	61.27	$562,244	$853,605	$13,367	$927,591	$608,551	$113,243	$91,799	$87,573	$26,425	$0	$501,625
7.60%	2006	7462	835	880	9177	62.51	$573,673	$893,432	$12,403	$1,050,555	$627,369	$117,082	$95,330	$87,573	$26,425	$96,777	$428,953
	2007	7462	835	880	9177	62.72	$575,551	$936,495	$13,919	$981,724	$648,522	$121,061	$98,154	$87,573	$26,425	$0	$544,240
Tax Rate	2008	7462	835	880	9177	65.78	$603,685	$962,632	$11,524	$1,010,733	$669,898	$125,154	$101,685	$87,573	$26,425	$0	$567,107
41.49%	2009	7462	835	880	9177	66.06	$606,151	$1,010,213	$13,738	$1,040,973	$692,362	$129,397	$105,216	$87,573	$26,425	$0	$588,131
	2010	7462	835	880	9177	68.94	$632,707	$1,040,110	$13,658	$1,225,914	$710,916	$133,784	$109,452	$87,573	$26,425	$157,764	$460,661
	2011	7183	835	880	8898	70.07	$623,443	$1,066,174	$14,246	$1,067,976	$709,991	$135,798	$112,983	$82,779	$26,425	$0	$636,887
	2012	7183	835	880	8898	71.36	$634,919	$1,119,973	$15,745	$1,105,129	$738,073	$140,632	$117,220	$82,779	$26,425	$0	$665,509
Post 2014	2013	7183	835	880	8898	76.30	$669,986	$1,158,214	$13,542	$1,136,809	$763,858	$145,639	$121,457	$82,779	$23,077	$0	$704,933
Inflation	2014	6719	835	880	8434	78.99	$666,207	$1,100,281	$14,326	$1,205,664	$790,508	$150,824	$111,427	$82,779	$19,251	$50,876	$575,151
3.56%	2015	5638	0	880	6518	81.80	$533,190	$1,000,817	$14,837	$966,326	$669,132	$122,326	$96,654	$58,964	$19,251	$0	$582,517
	2016	5638	0	880	6518	84.71	$552,172	$1,036,448	$15,365	$995,080	$692,369	$126,680	$100,331	$58,964	$16,735	$0	$608,905
	2017	5167	0	880	6047	87.73	$530,508	$974,546	$15,912	$897,135	$597,408	$120,021	$104,008	$58,964	$16,735	$0	$623,830
	2018	5167	0	880	6047	90.85	$549,394	$1,009,241	$16,478	$926,769	$618,091	$124,294	$107,685	$58,964	$16,735	$0	$649,344
	2019	4811	0	880	5691	94.09	$535,457	$985,591	$17,065	$936,483	$625,754	$123,143	$111,887	$58,964	$16,735	$0	$601,619
	2020	4667	0	880	5547	97.44	$540,488	$1,001,032	$17,672	$933,519	$622,587	$124,389	$116,090	$56,378	$14,075	$0	$625,673
	2021	4196	0	880	5076	100.91	$512,202	$922,654	$18,301	$814,139	$507,265	$115,971	$120,450	$56,378	$14,075	$0	$639,019
	2022	3844	0	880	4724	104.50	$493,653	$876,430	$18,953	$793,762	$482,633	$115,702	$124,974	$56,378	$14,075	$0	$595,274
	2023	3844	0	880	4724	108.22	$511,227	$907,632	$19,628	$812,612	$499,231	$119,821	$129,668	$56,378	$7,514	$0	$625,875
	2024	3844	0	880	4724	112.07	$529,427	$939,943	$20,326	$838,936	$516,420	$124,087	$134,538	$56,378	$7,514	$0	$650,760
	2025	2689	0	880	3569	116.06	$414,223	$591,080	$21,050	$531,129	$329,040	$71,852	$87,551	$33,770	$9,916	$0	$495,225
	2026	1627	0	880	2507	120.19	$301,325	$487,882	$21,798	$425,434	$259,004	$65,120	$65,045	$27,349	$8,916	$0	$385,572
	2027	1627	0	880	2507	124.47	$312,052	$505,250	$22,575	$439,124	$267,933	$67,439	$67,488	$27,349	$8,916	$0	$400,753
	2028	1627	0	880	2507	128.90	$323,161	$523,238	$23,379	$453,306	$277,179	$69,839	$70,023	$27,349	$8,916	$0	$416,471
	2029	1627	0	880	2507	133.49	$334,665	$541,366	$24,211	$467,998	$286,755	$72,326	$72,663	$27,349	$8,916	$0	$432,744

NPV of Net Margins After Tax $3,305,937

PAIEUG STATEMENT NO. 3S

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	)	

SURREBUTTAL TESTIMONY

OF

LANE KOLLEN

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

NOVEMBER 1997

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
	)	
V.	)	**DOCKET NO. R-00973953**
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

SURREBUTTAL TESTIMONY OF LANE KOLLEN

I. 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. Have you previously filed testimony in this proceeding on behalf of PAIEUG?

A. Yes. I previously filed direct testimony regarding the proper quantification of certain PECO stranded costs and assets. I addressed the statutory guidelines for quantification of stranded costs for purposes of CTC recovery, regulatory assets/liabilities, fossil and nuclear decommissioning, other transition costs, and the appropriate discount rate and grossed-up rate of return. The regulatory assets/liabilities that I addressed included the following:

- SFAS 109 net regulatory asset.
- Deferred fuel.
- Pension overfunding.
- SFAS 106.
- Limerick 1 and 2 declaratory orders.
- Nuclear design basis documentation and Peach Bottom/Limerick water chemistry.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to address by issue the rebuttal testimony of PECO witnesses as follows:

	Issue	PECO Witness(es)
•	SFAS 109 net regulatory asset	Cohn, Warren, McKnight, Sharpe
•	Deferred fuel	Cohn
•	Pension overfunding	Cohn
•	SFAS 106	Cohn
•	Nuclear design documentation and water chemistry changes	Cohn
•	Nuclear decommissioning	Cohn, LaGuardia
•	Fossil decommissioning	Cohn, Stout, LaGuardia

Q. Please summarize your testimony.

A. The conclusions and recommendations in my direct testimony remain unchanged. A summary of my surrebuttal response to each issue is included at the beginning of each of the following sections of this testimony.

II. SFAS 109

Q. Please summarize your conclusions regarding the SFAS 109 regulatory asset.

A. The Company's proposal to state the SFAS 109 asset on a nominal basis and then to quantify the effect in its levelized revenue requirement computation over seven years results in a violation of the provisions of the Act. The Act specifies how regulatory assets are to be quantified. First, the Act requires all regulatory assets to be stated on a net present value basis, not a nominal basis. There is no exception for the SFAS 109 regulatory asset. Second, the Act limits the quantification of regulatory assets to that which is recoverable under traditional regulation. Again, there is no exception for the SFAS 109 regulatory asset.

Although the Company's rebuttal witnesses have attempted to redefine "traditional regulation," the fact is that traditional regulation provides for recovery of the SFAS 109 asset over the underlying service lives of the physical assets. To compute the net present value of the SFAS asset over seven years or a shorter period will impose severe economic harm on customers, a result that could not reasonably have been intended under the Act.

Finally, a writeoff will not be required if the SFAS 109 asset is quantified as the net present value of the tax amounts over the 27 year average underlying lives of the physical assets. First, PECO acknowledges that there will be no writeoff if the net present value is computed over seven years, assuming a straight line amortization. Second, it is arguable whether PECO will actually "repay" these government loans in whole or part over the seven year CTC period. This is largely an accounting fiction. Third, to the extent that there is an "economic" loss, the accounting rules do not require a writeoff. The accounting rules allow the asset as well as the liabilities to be retained on the Company's accounting books and amortized over the life of the underlying physical assets.

Q. Please differentiate between the quantification of the SFAS 109 regulatory asset for book accounting purposes and for CTC purposes.

A. The two quantifications are completely different conceptually. For book accounting purposes, the projected tax payments for all future years are summed. This sum is booked as a SFAS 109 accumulated deferred tax liability. Concurrently, an equivalent regulatory asset is booked. Neither are stated on an economic or discounted basis to reflect the fact that the collection of the tax obligation will occur for many years into the future. In contrast to the book accounting, the Act correctly recognizes that regulatory

assets must be stated on an economic basis, discounted for the time value of the future collection entitlement from ratepayers. Thus, there is a difference in the quantification for book accounting purposes and the requirements of the Act due solely to the effect of discounting.

The nominal value of the SFAS 109 asset for book accounting purposes at December 31, 1998 is projected by the Company to be $1,687.079 million. The economic value of the SFAS 109 asset for purposes of the Company's CTC proposal at December 31, 1998 is $1,318.709 million. The economic value of the SFAS 109 asset under the PAIEUG recommendation at December 31, 1998 is $736.153 million.

Q. Was PECO required to write off the difference between the book accounting (nominal) and the economic quantifications of the SFAS 109 asset?

A. No. Despite the fact that the SFAS 109 regulatory asset is currently reflected on PECO's books on a nominal dollar basis, PECO was not and is not required to write off the portion of the nominal dollar quantification in excess of the economic or discounted quantification.

Q. What will be the impact on the economic value of the SFAS 109 regulatory asset under PECO's proposal?

A. PECO's proposal is to "write-up" the economic value of its SFAS 109 regulatory asset by reducing the time period and front loading the amortization of the future tax entitlement. PECO's witnesses Mr. Warren, Mr. McKnight, and Mr. Sharpe are concerned that if PECO is not allowed to "write-up" the economic value of the SFAS 109 regulatory asset, then it will suffer economic harm.

Q. If PECO is allowed to "write-up" the economic value of the SFAS 109 asset, what will be the economic impact on ratepayers?

A. PECO's proposal will result in an economic "write-up" of $582.556 million on a net present value basis, the responsibility for which PECO would impose upon the ratepayers as an additional CTC stranded cost. That amount is the difference between the economic values of $1,318.709 million under the PECO proposal and $736.153 million under the PAIEUG recommendation.

Q. Is such a penalty on ratepayers authorized directly or as an "exception" for CTC recovery under the Act?

A. No. There is simply no provision for such a penalty to be imposed on ratepayers, nor would it have been reasonable for the Act to include such a provision. The Act specifically mandates the principles for quantification, i.e., the regulatory assets must be stated at net present value and on the basis of traditional regulation. The Act neither authorizes nor mandates the penalty proposed by PECO and its rebuttal witnesses.

Q. Will your recommendation to compute the net present value over the lives of the underlying physical assets result in a writeoff?

A. No. Both Mr. Sharpe and Mr. McKnight are mistaken on this point. Both base their writeoff arguments on the "economic" value of the SFAS 109 regulatory asset. However, the accounting rules do not recognize the economic value, but rather the undiscounted nominal value of the asset, as I previously discussed.

In addition, the accounting entries reflecting the alleged writeoff and quantification in Mr. Sharpe's testimony are wrong and misleading. Fundamentally, Mr. Sharpe incorrectly computed the alleged writeoff as the difference between the book accounting and the economic value of the SFAS 109 regulatory asset. Under Mr. Sharpe's presentation, PECO would be required to writeoff $368.360 million under its CTC proposal, computed as the difference between the nominal book accounting amount of

$1,687.069 million and the economic value under the PECO proposal of $1,318.709 million. That simply is incorrect. No other PECO witness supports such a mistaken notion.

The absurdity of Mr. Sharpe's presentation should be clear. The economic value has never been the basis for quantification of the SFAS 109 regulatory asset. Thus, the quantification of the economic value of the asset does not create a writeoff in and of itself. If any writeoff is required, with which I disagree, then it would be equivalent to the economic value of the SFAS "write-up" sought by PECO, computed as the difference between the net present value of a seven year and 27 year amortization.

Further, there is no question that the Company will receive its entitlement to future taxes on a nominal basis, whether over seven years or 27 years. Even PECO witness Mr. Warren acknowledges that to the extent the Company obtains recovery over seven years compared to 27 years, ratepayers are entitled to the time value of this prepayment, although he alleges this to be true only for nonstranded (market valuation) generation costs. Since the Company will receive its full entitlement to future taxes on a nominal basis, there is no predicate for an SFAS 109 writeoff due to an amortization period reflecting traditional regulation.

Finally, neither Mr. Sharpe nor Mr. McKnight informed the Commission that the alleged writeoff threat, if the Commission perceives it to be real, can be resolved readily through the Commission's authorization of a deferred regulatory asset equivalent to the nominal dollars the Company will "prepay" in taxes over the seven year CTC period compared to the 27 years average physical life of the assets. The accounting entries would be to remove the nominal balance of SFAS 109 deferred tax liabilities and the equivalent SFAS 109 regulatory asset from the generation company's accounting books and to book a deferred (prepaid) tax asset and equivalent regulatory liability on the distribution company's accounting books. Both the deferred tax asset and the regulatory liability will reverse over the remaining 27 years average physical lives of the underlying assets.

Q. Has PECO properly provided "credit" to the ratepayers for the SFAS 109 regulatory asset it allegedly allocated to market value?

A. No. As described by PECO witness Mr. Hill in his direct testimony and referred to by Mr. Cohn in his rebuttal testimony, the Company allocated the liability balance of accumulated deferred taxes between stranded generation costs and market value. According to Mr. Cohn, the PECO allocation to market value was higher because it included some amount of SFAS 109 liability accumulated deferred income taxes.

Although the PECO methodology for allocating the liability balance of accumulated deferred taxes, which is incorrect for the reasons I described in my direct testimony, did incorporate the SFAS 109 liability balances, it was only for computing the allocation percentage. The allocation percentage was applied to the liability balance of accumulated deferred income taxes, excluding the SFAS 109 deferred tax liability balance. The total liability accumulated deferred tax balance allocated between stranded generation cost and market value did not include the SFAS 109 liability balance. Thus, there is no SFAS 109 "benefit" as alleged by Mr. Cohn and cited by Mr. Warren and Mr. McKnight.

Q. If Mr. Cohn's logic of allocating the SFAS 109 and the accumulated deferred tax liability actually had been followed by PECO, what would have been the result?

A. A portion of the SFAS 109 regulatory asset would have been discounted over 27 years. The portion would have been determined by the ratio of the market value of generation assets to the total net book value of generation assets at December 31, 1998.

III. DEFERRED FUEL

Q. Please summarize your conclusions and recommendations regarding the Company's claim for deferred fuel costs as a regulatory asset.

A. The Company should be allowed stranded cost recovery of its deferred fuel at December 31, 1996. Any deferrals subsequent to December 31, 1996 should not be allowed. For the period January 1, 1997 through December 31, 1998, the Company failed to demonstrate that it would underrecover and failed to quantify any underrecovery. The only evidence it has presented, despite specific requests for it earlier through discovery, was provided for the first time in the Company's rebuttal case and then for only a portion of the two year period. For the five year period subsequent to December 31, 1998, there is no evidence whatsoever the Company will underrecover and its request represents nothing more than sheer speculation.

Q. Is the Company's estimate of deferred fuel costs reasonable?

A. No. The Company offered no evidence in its filing that post-1996 projections of fuel costs were reasonable. When offered the opportunity for such a demonstration in

discovery, the Company failed to provide any computations or other evidence other than vague statements that its fuel costs were projected to increase.

In his rebuttal testimony, Mr. Cohn provides a "check on the reasonableness" of the projection provided in the P-00961128 and R-00963838 proceedings. Thus, PECO now has presented a computation of its alleged underrecoveries, but only for the first five months of 1997. I did not assess the validity of this computation due to the Company's failure to produce it earlier; however, even assuming its validity, five months of alleged underrecovery fails to address the remainder of the January 1, 1997 through December 31, 1998 period or the period subsequent to December 31, 1998.

IV. PENSION OVERFUNDING

Q. Please summarize your conclusions and recommendations regarding the pension fund overfunding.

A. The Company's pension fund is overfunded through amounts collected from ratepayers. The quantification included in my direct testimony is understated given that the Company has continued to collect pension expense from ratepayers but has discontinued contributions to the pension fund. The pension fund excess continues to grow as the fund investments appreciate. The fund managers historically have beaten the fund earnings assumption incorporated in the pension expense computation.

The full benefits of the pension overfunding have not been provided to ratepayers, contrary to PECO witness Mr. Cohn's claim. First, the earnings assumption is understated given historical experience. Second, the company failed to include pension expense in the incremental cost of new capacity, thereby understating market revenues. Thus, PECO has coupled a pension expense that should be negative with no revenues to recover the pension expense associated with incremental new capacity, thereby reducing PECO's market valuation and increasing its generation stranded cost.

Q. Is the historic earnings rate the reason for the pension overfunding?

A. Yes. The historic earnings rate has far exceeded the assumptions utilized by PECO in its current pension fund expense computations. This has two effects. First, PECO's annual pension expense projection is excessive, thereby understating its market valuation and overstating its generation stranded cost. Second, annual pension expense has been rapidly declining as the result of the excess funding and continued earnings on the excess funding. At the same time, PECO's current rates reflect much higher pension expense, which it has retained for its shareholders since its last base rate case. This has led to a further overstatement of pension expense, thereby further understating market value and overstating generation stranded costs.

Q. Did PECO include pension expense in its computations of the incremental cost of new generation capacity?

A. No. This also had the effect of understating the market valuation of its generating assets and overstating the generation stranded cost.

V. SFAS 106

Q. Please summarize your conclusions and recommendations regarding the SFAS 106 issues.

A. I have no changes to the conclusions and recommendations on the SFAS 106 issues described in my direct testimony. The Company has retained all savings from its early retirement programs, which more than offset the SFAS 106 stranded cost claim sought in this proceeding. PECO's claim represents impermissible retroactive and single issue ratemaking. Finally, it is the interest income on the SFAS 106 funds collected in excess of cash pay-as-you-go that results in my recommendation for a net SFAS 106 regulatory liability.

Q. Mr. Cohn asserts that the savings associated with PECO's early retirement programs are fully recognized in the Company's market valuation. Please respond.

A. In my direct testimony, I stated that one reason for not allowing the retroactive recovery of early retirement program costs expensed by the Company in 1995 was that the Company had retained the savings since then. Consequently, the Company's request, in addition to being impermissible retroactive ratemaking, was not equitable and was

one-sided, considering only the costs, but no offsetting savings. That has nothing to do with Mr. Cohn's attempt to recharacterize my argument as somehow affecting the market valuation. Thus, his rebuttal on this point is irrelevant and should be ignored.

Q. Mr. Cohn further asserts that the Company's early retirement program costs have not been recovered from ratepayers. Please respond.

A. Again, this simply further confirms the point that I made in my direct testimony, that the savings retained by the Company in 1995, 1996, and 1997 have exceeded the costs of the programs. In addition, it will retain the savings for 1998. Mr. Cohn acknowledges the savings, but inexplicably still asserts there should be no offset to its claimed SFAS 106 cost. It is clear that the Company has not been harmed, but rather has benefitted.

Q. Mr. Cohn argues that your recommendation constitutes "impermissible line-item ratemaking." Please respond.

A. To the contrary, it is the Company's request that constitutes impermissible line-item (single issue) and retroactive ratemaking. I recommend that it be rejected on those bases. The Company expensed the SFAS 106 amounts associated with the early retirement programs, along with its other early retirement program costs, it had no

Commission order authorizing the deferral of only the SFAS 106 amounts, and it is seeking recovery years after the incurrence of the expense. In contrast, PECO has offered no retroactive ratemaking for benefits achieved in earlier years such as expense savings or additional revenues due to abnormal weather. It should be obvious that PECO's attempt reflects a textbook example of very selective, single issue, and impermissible retroactive ratemaking. It should be rejected.

Q. Mr. Cohn suggests that you have a misunderstanding regarding the effect of interest income on the SFAS 106 expense computation. Please respond.

A. Mr. Cohn's premise lacks factual foundation. To the contrary, it is the very fact that there is interest income in the SFAS 106 computation that provides the foundation for my recommendation regarding the SFAS 106 regulatory liability. The ratepayers have prepaid this future liability and are entitled to the interest income as either a regulatory liability or as a higher market valuation for the generation assets. Otherwise, the interest income will be retained by PECO either in the form of lower SFAS 106 expense, if there is an external fund, or through the Company's overall rate of return, if the expense in excess of cash payments is simply retained and used for other Company purposes.

VI. NUCLEAR DESIGN BASIS DOCUMENTATION AND WATER CHEMISTRY CHANGES

Q. Please summarize your conclusions and recommendations regarding the nuclear design basis documentation and water chemistry changes.

A. These costs were not authorized for deferral or future regulatory recovery by the Commission. The recovery of these costs now would represent improper retroactive ratemaking. In addition, the Company's proposal provides for an accelerated amortization of these costs, which improperly increased the net present value of these assets and the Company's stranded cost claim. I recommend that the costs not be allowed. However, if the costs are allowed, then the net present value should be computed over the remaining lives of the nuclear generation units assuming no return on the unamortized balances.

Q. Has Mr. Cohn provided the Commission with any additional relevant information on these issues in his rebuttal testimony?

A. No. He simply reiterated his direct testimony. He failed to respond to my recommendation that if the Commission does allow recovery of these costs, then the net present value should be computed over the remaining lives of the nuclear units with no return on the unamortized balance. Thus, I have no further response.

VII. NUCLEAR DECOMMISSIONING

Q. Please summarize your conclusions and recommendations.

A. I continue to recommend that the Commission recognize a regulatory liability for the decommissioning costs collected from ratepayers prior to January 1, 1999 in order to properly reflect earnings on the decommissioning trust fund in excess of the decommissioning cost escalation. I continue to recommend the lower nuclear decommissioning expense annuity included by PAIEUG witness Mr. Falkenberg in his market valuation for years after December 31, 1998. I also continue to recommend the use of the 7.5% trust fund earnings rate to recognize a continuation of the tax qualified status of the trust fund.

Alternatively, if the Commission accepts PECO's offer to utilize an annuity computation for the total nuclear decommissioning effect, then I recommend that the regulatory asset/liability be set to zero and the expense annuity recommended by OCA witness Mr. Catlin be incorporated in the market valuation of generation assets.

Q. Does the Company agree that an annuity method could be appropriately implemented?

A. Yes. Mr. Cohn agrees that PECO would find an annuity method of expense accrual computation acceptable, if it is treated as a separate charge on the regulated distribution company.

Q. Is that condition acceptable to PAIEUG?

A. Yes, but with certain important caveats. It is essential to preserve the tax qualified factors of the fund and the deductibility of fund contributions as well as the lower income tax rate on fund earnings. However, the Commission must be careful to remove this cost from the market valuation, to set the regulatory asset claimed by PECO to zero, and to limit the ability of the Company to obtain single issue rate increases simply by increasing its decommissioning cost estimates..

PAIEUG believes that the annual expense accrual computed by OCA witness Mr. Catlin, adjusted to the higher earnings rate of 7.5% (which assumes the trust fund will continue to be tax qualified), is appropriate in lieu of this concession by PECO. Otherwise, the PAIEUG recommendations in my direct testimony regarding a regulatory liability and lower future expense accruals (utilized in the market value quantification by Mr. Falkenberg) should be adopted.

Q. Please respond to Mr. LaGuardia's claim that post retirement trust fund earnings should not be incorporated into the computation of the annual expense accruals.

A. The Commission should incorporate post-retirement trust fund earnings because it is appropriate to do so and it is consistent with its decision on this issue in the recent PP&L base rate proceeding in Docket No. R-943271.

It is appropriate to incorporate the post-retirement trust fund earnings into the annuity expense accrual because the ratepayers are entitled to all earnings on funds they have prepaid. To allocate those earnings to the Company's shareholders would be a gross injustice and lacks any foundation of valid regulatory principle.

Notably, Mr. Cohn, one of the Company's regulatory experts, did not argue against the reflection of post-retirement trust fund earnings in the annuity expense computations. Mr. Cohn did not identify the exclusion of these earnings as a condition precedent to PECO's agreement to accept the annuity decommissioning expense computation. Thus, the Commission should reject Mr. LaGuardia's claim and incorporate the post-retirement trust fund earnings into the expense accrual.

VIII. FOSSIL DECOMMISSIONING

Q. Please summarize your conclusions and recommendations regarding fossil decommissioning.

A. I continue to recommend no recovery of these projected costs because they are inherently speculative and uncertain. In addition, PECO's quantifications contain gross errors which significantly overstate PECO's stranded cost claim.

Q. What response has PECO provided to your claim that its fossil decommissioning study contained errors with respect to the retirement dates of the Keystone and Conemaugh generating units?

A. Mr. LaGuardia, the Company's witness sponsoring the decommissioning study, failed to address these errors. Mr. Stout, who assures the Commission that Mr. LaGuardia's study is "reasonable," basing his assessment on Mr. LaGuardia's expertise, also failed to address these problems. The only PECO witness to address these problems, Mr. Cohn, assures the Commission that it would be "inappropriate" to reflect the same life extension for decommissioning purposes as the Company incorporated in its market valuations! The reason provided was that no "official" decisions had been made regarding the life extensions and "a number of factors affecting such decisions could change over the intervening years." He then proceeds to argue that a longer or shorter life will not result in an underrecovery or overrecovery.

Q. Do you agree that these errors by PECO are irrelevant and will not affect the stranded cost claim?

A. No. First, the errors illustrate a lack of attention to and consistency on such important issues as the Company's plans to retire some of its largest generating units. Second, such errors and Mr. Cohn's attempted rationalization illustrate the speculative and uncertain nature of these costs. Third, if fossil decommissioning is allowed as a stranded cost, the timing of the future costs directly impacts the net present value of this claim.

Q. Mr. LaGuardia asserts that his fossil decommissioning study is not inherently speculative and uncertain. Please respond.

A. Although Mr. LaGuardia's studies are detailed and based on many assumptions, that does not increase the accuracy of the cost estimate. A speculative and uncertain cost estimate can be made with great precision, but important assumptions must still be made and still directly impact the result. These assumptions are inherently uncertain and speculative, regardless of Mr. LaGuardia's stated "care for accuracy in these estimates." Mr. LaGuardia's "care for accuracy" did not extend to important assumptions such as retirement dates for major generating units.

It is paradoxical that Mr. LaGuardia should so strongly defend the "certainty" of his cost estimates, when there exists the acknowledged (by Mr. Cohn only) clear errors regarding

the retirement dates of the Keystone and Conemaugh units, and when Mr. LaGuardia subsequently asserts that the future usefulness of the plant sites cannot be forecasted stating:

> **"The uncertainty in forecasted detailed, specific site plans so far into the future simply renders such an undertaking impractical."**

Yet, Mr. LaGuardia is capable in his estimation of not only making a "certain" site specific cost estimate, but then also making a "certain" estimate for contingencies, which he has taken great effort to redefine from the common usage of that term.

It is clear that such cost estimates, even if rendered with professional judgment and with precision and care, are still inherently uncertain and speculative.

Q. **Mr. Stout finds that Mr. LaGuardia's fossil decommissioning cost estimates are reasonable because they fall within the range of estimates contained in a "paper" presented by a person who is not a witness in this proceeding. Please respond.**

A. First, there is no witness in this proceeding who personally prepared or is knowledgeable regarding the data and analysis in this paper.

Second, a former colleague of Mr. Ferguson's, Mr. Donald Roff of Deloitte-Touche, recently prepared a study of gas and coal fired decommissioning cost estimates and filed it with his testimony in an Entergy Gulf Sates Utilities, Inc. depreciation proceeding before the Louisiana Public Service Commission. In that study, the range for decommissioning gas fired units was $5/kW to $177/kW and the range for coal fired units was $5/kW to $157/kW, with the exception of one utility. The range of such cost estimates actually is much higher than portrayed by Mr. Stout, and the fact that Mr. LaGuardia's estimates in this proceeding fall within some range in some study fails to demonstrate, in and of itself, that Mr. LaGuardia's estimates are reasonable.

Q. Both Mr. Cohn and Mr. Stout argue that the Penn-Sheraton decision should not apply. Please respond.

A. Mr. Stout selectively cites the Act, implying that the Act requires the Commission to allow recovery. However, the Act contains no requirement to allow recovery of fossil decommissioning costs, instead providing the Commission the following guidance in §2808(C)(3):

> **"The Commission shall determine the level of other generation-related transition or stranded costs that may be recovered through the competitive transition charge."**

Mr. Stout also argues that the Penn-Sheraton case should not apply since "the market will not reflect such costs." If that is true, it cannot be true only for PECO. If all generation providers, including incremental new generation capacity, have to recover decommissioning costs through market revenues, then everyone is on a comparable competitive basis. As PAIEUG witness Mr. Falkenberg notes, PECO failed to include decommissioning costs in its projections of the incremental costs of new generating capacity.

Q. Does this complete your surrebuttal testimony?

A. Yes.

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PAIEUG EXHIBIT NO. 1A

COMMISSIONER INFORMATION REQUESTS
SET NO. 2

R-973953

Q1. How are the terms of the IECPA settlement provisions handled in the Enron proposal.

A1. We assume that the question is directed to those portions of the proposed joint settlement agreement generally referring to PAIEUG member interests, since IECPA is not a party to this matter. Please refer to Answer of the Philadelphia Area Industrial Energy Users Group in Opposition to the Petition of Enron Energy Services Power, Inc., for Approval of an Electric Competition and Customer Choice Plan, ¶ 33, at pp. 29-31, for a detailed discussion of various riders and special contract provisions that are protected by the Joint Petition but are either eliminated or modified adversely in Enron's proposal.

Q2. What are Enron's present and anticipated future relationships with the PJM?

A2. This question is not directed to PAIEUG; therefore, a response is not provided.