R00973953

PA[illegible] STATEMENT NO. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

JUNE 1997

BEFORE THE

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TABLE OF CONTENTS

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

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

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. **Please state your educational background.**

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. **Please describe your professional experience.**

A. I have more than twenty-two years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North

Carolina, Ohio, Pennsylvania, Texas, West Virginia, Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1)

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

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

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

A. I will be presenting testimony on three areas in this proceeding. The first group of issues concerns a summary of PAIEUG's stranded cost analysis, as prepared by PAIEUG witnesses Randall J. Falkenberg and Lane Kollen. Mr. Falkenberg has prepared PAIEUG's market value analysis and has calculated the stranded costs associated with PECO's generation assets. Mr. Kollen is presenting PAIEUG's analysis of PECO's claim for regulatory assets. In my testimony, I will present PAIEUG's overall stranded cost revenue requirements, relying on the individual calculations prepared by Mr. Falkenberg and Mr. Kollen.

The second set of issues concerns a number of regulatory policy issues associated with the calculation of stranded costs and the recovery of CTC's from ratepayers. Among the issues that I will be addressing is the just, reasonable and appropriate level of quantifiable stranded costs that are recoverable from ratepayers. As I will discuss, PAIEUG is proposing a form of common equity disallowance on the calculation of the revenue requirement associated with the Commission-approved stranded generation cost.

The next policy issue that I will discuss concerns PAIEUG's recommended mechanism for tracking revenues produced by the CTC component of each unbundled rate. PECO proposes such a CTC tracking mechanism but does not specifically address the approach that the Company will use. I will also be addressing PAIEUG's proposal to extend the generation rate cap provision of the Electricity Generation Customer Choice and Competition Act ("the Competition Act"), if it is necessary to extend the period of CTC recovery beyond seven years. Although PAIEUG does not believe that PECO should automatically be able to recover the CTC once the seven year period defined in the Competition Act is exceeded, we do believe that it is reasonable to give PECO an opportunity to request (through a formal filing) such an extension beyond seven years, as long as the rate cap is extended concurrently.

I will also discuss the policy implications of PECO's proposed rate design on the development of a competitive market and a recommendation for an alternative approach that we believe is more suitable to a competitive environment.

The final set of issues that I will address in my testimony concerns PECO's proposed rate design methodology, with particular emphasis on rate schedule HT. In this portion of my testimony, I will discuss a number of issues related to PECO's proposed unbundling analysis and present an alternative rate design that directly employs the market prices developed on behalf of PAIEUG by Mr. Falkenberg. In addition, I will also address various rate design policy issues associated with the Company's filing that PAIEUG believes should be clarified in the Commission's order in this proceeding.

Summary

Q. Would you please summarize your testimony in this proceeding?

A.

- PAIEUG recommends a total stranded cost quantification for PECO of $2.21 billion. This includes $1.4 billion of stranded generation costs and $805 million of regulatory assets, including nuclear decommissioning.

- PECO's generation stranded costs should be reduced by $473 million to reflect a partial sharing of the costs by the Company's shareholders. This reduction has been factored into our recommended level of $1.4 billion of generation stranded costs.

- PECO should be permitted to accrue a fully grossed-up rate of return on the unamortized balance of stranded costs during the period of time (up to seven years) in which the Company is collecting CTC revenues from its customers. Our recommended overall rate of return is 8.73%, which, when grossed-up to a revenue requirement level is 12.35%.

- The appropriate basis for unbundling PECO's rates is to utilize expected market rates for each year of the seven year transition period, while computing the CTC as a residual in the analysis. This is in contrast to PECO's method that allocates a CTC revenue requirement to each rate class, leaving a hypothetical "market rate" as the residual. PECO's methodology is inappropriate and could lead to anti-competitive rates.

- LILR customers should pay CTC charges associated with the rate schedule HT portion of their usage. LILR customers should not pay a CTC on the supplemental energy portion of their usage that represents purchases of PJM market energy on an interruptible basis.

II. STRANDED COST ANALYSIS -- SUMMARY OF PAIEUG RESULTS

Q. Would you please discuss PAIEUG's recommendation for stranded cost recovery by PECO Energy Company in this proceeding?

A. PAIEUG is recommending that PECO be permitted to recover approximately $2.21 billion of stranded costs from ratepayers. This $2.21 billion stranded cost value includes both generation related stranded costs and regulatory assets (including nuclear decommissioning) <u>on a present value revenue requirement basis</u>. In essence, PAIEUG's recommendation is that ratepayers should compensate PECO for stranded costs by an amount of $2.21 billion (present value) for a period not to exceed seven years.

Q. Would you please explain the basis for PAIEUG's $2.21 billion present value stranded cost revenue requirement?

A. Baron Exhibit ____(SJB-2) shows a summary (top portion of exhibit) of the analysis used to develop the stranded cost recommended by PAIEUG. This analysis reflects both the calculation of the cost associated with stranded generation plant as well as incorporating the present value of regulatory asset revenue requirements prepared by

Mr. Kollen in his testimony. It also reflects our proposed adjustment for a portion of the generation related stranded costs.

The first portion of the analysis compares PECO's net generating plant and CWIP balance at December 31, 1998 of $6,688.384 million (as calculated by PECO) to PAIEUG's market value for PECO generating units of $4,811.327 million. The resulting difference represents the stranded cost directly associated with generating plant of $1,877.057 million.

The next step in the analysis is to reduce the stranded generation plant value by an equity return disallowance, assuming a full seven year CTC recovery period. This disallowance, which reflects a just and reasonable level of recovery from ratepayers, and effectively, a sharing of a portion of the generation related stranded cost by PECO shareholders is $472.822 million. Finally, the stranded cost associated with regulatory assets of $805.177 million is added to produce an overall stranded cost value for PECO of $2,209.412 million.

This amount, which reflects a present value, is the appropriate level of stranded cost recovery for PECO, if it is assumed that ratepayers paid the entire amount on January 1, 1999.

Q. Have you calculated the levelized annual revenue requirements associated with your recommended $2.21 billion in stranded cost recovery for PECO?

A. Yes. Although PAIEUG is recommending an alternative approach to recovering stranded cost from ratepayers that does not utilize an annual, levelized CTC revenue requirement, I have calculated such a value.

If the Commission should adopt PECO's methodology (that computes a seven year levelized CTC revenue requirement) the PAIEUG seven year levelized annual CTC revenue requirement that corresponds to our recommended $2.21 billion of stranded cost is $486.516 million. The present value of this CTC revenue requirement is $2.55 billion, which corresponds to PECO's present value revenue requirement of $6.9 billion (shown on page 1 of 5, Schedule 10 of Mr. Cohn's testimony). These calculations are shown on Baron Exhibit ____(SJB-2)

Q. Please describe the approach that PAIEUG is proposing to develop the CTC for each rate schedule and recover your recommended $2.21 billion of stranded cost?

A. PAIEUG is proposing an unbundling methodology that develops the CTC component of each unbundled rate as a residual, after removing transmission, distribution and expected market prices from current bundled rates. As a result, there is no need to calculate an annual, levelized stranded cost revenue requirement in order to allocate CTC costs to rate classes. Since the CTC for each class is computed as a residual, it is only necessary to develop an accrual methodology to accumulate CTC revenues from each rate class and, effectively amortize the $2.21 billion stranded cost balance during the seven (or fewer) year transition period.

During the CTC recovery period, PECO should be permitted to earn a fully grossed-up return (revenue requirement "level" return) on the unamortized stranded cost balance. As discussed by PAIEUG witness Kollen, our recommended overall rate of return is 8.73%, which, when grossed-up to a revenue requirement level is 12.35%.

Q. **Would you please discuss the specific methodology that you have utilized to produce a just and reasonable level of quantified stranded costs that can be recovered from ratepayers?**

A. PAIEUG is recommending an equity disallowance on the recovery of stranded generation costs, assuming a seven year recovery period. This equity return disallowance is calculated by comparing the present value of the revenue requirements associated with stranded generation costs, calculated at a fully grossed-up return level, and a similar calculation that excludes the equity return component. This analysis is shown on Baron Exhibit ____(SJB-3), pages 1 and 2.

On page 1 of Baron Exhibit ____(SJB-3), the present value of stranded generation plant revenue requirements is calculated using a debt only return of 3.96% on the unamortized balance. The annual revenue requirements, amortized over the full seven year CTC recovery period are present valued at an after-tax rate of return of 7.23%. The resulting present value revenue requirements associated with stranded generation cost of $1.877 billion is $1.693 billion. To develop the equity return disallowance, a similar calculation is performed under the assumption of a fully grossed-up rate of return on the unamortized stranded generation cost balance, assuming amortization over seven years. The resulting present value of revenue requirements, including an equity return component is shown on page 2 of 2 of the exhibit to be $2.166 billion.

The equity return revenue requirement, which is the difference between the two present value calculations is $472.822 million. This is the amount of stranded generation cost that should be disallowed and effectively represents a sharing of stranded generation cost by shareholders. PAIEUG believes that this approach produces a just, reasonable and appropriate level of quantified stranded costs that can be recoverable from PECO's ratepayers, and effectively leads to a sharing of the stranded costs associated with PECO's generation plant.[1]

Q. How have you developed the return on the unamortized stranded generation costs in this proceeding?

A. Baron Exhibit ____(SJB-4) shows the development of the rate of return utilized to calculate revenue requirements. The capital structure shown in Baron Exhibit ____(SJB-4) reflects the cost of debt and preferred assumed by PECO in this proceeding, without any common equity return. Since the common equity return is eliminated, the tax gross-up associated with the common equity return is also eliminated in the analysis. As can be seen in the exhibit, the resulting rate of return appropriate for calculating stranded generation cost revenue requirements during the seven year transition period is 3.96%. Also shown on the exhibit is the full rate of return calculation.

Q. Have you included all of the regulatory assets and liabilities, as well as nuclear and fossil decommissioning in your analysis, similar to the approach outlined by PECO witness Hill in Exhibit TPH-7?

[1] PAIEUG's proposed adjustment is only applicable to stranded generation costs, not regulatory assets or other stranded costs.

A. Effectively, the answer to this question is yes. However, as will be discussed by PAIEUG witness Kollen, we are not recommending that any fossil plant decommissioning be included as part of stranded costs. However, from the standpoint of presentation, Mr. Kollen has included all appropriately claimed stranded costs associated with regulatory assets, nuclear decommissioning and other transition costs (other than stranded plant). In the PAIEUG analysis, stranded costs are comprised of two distinct categories, stranded plant and stranded regulatory assets, including nuclear decommissioning and other transition costs.

III. REGULATORY POLICY ISSUES

<u>Discounting of Generation Stranded Costs</u>

Q. Would you please discuss your recommended position regarding the appropriateness of discounting (i.e., sharing) stranded generation costs, prior to recovery from PECO's ratepayers?

A. The Competition Act clearly defines a series of steps that a utility must follow before recovering stranded costs from ratepayers. The Act does permit a full, 100% recovery of stranded costs (after mitigation), associated with regulatory assets and non-utility generator ("NUG") purchased power contracts. However, with respect to the largest component of stranded costs, those related to generation assets, the Act requires the Commission first to consider whether or not the utility has undertaken reasonable efforts in mitigation and whether the asset is a properly claimable stranded cost; then, the Commission must quantify the properly claimed stranded costs and identify a just and reasonable level of these costs for recovery from ratepayers. This is consistent with Commissioner Hanger's statement that was attached to the Commission's order in the PECO QRO proceeding.

Q. ***Have you evaluated PECO's efforts at mitigating stranded costs?***

A. I have reviewed the testimony filed by PECO witnesses (particularly PECO witness Thomas Hill) regarding the Company's efforts to mitigate stranded costs. Although I have not analyzed each of these efforts in detail, I am not challenging PECO's mitigation efforts in this proceeding.

Q. **As you indicated in a previous answer, the Competition Act requires the Commission to determine a just and reasonable level of stranded generation costs that should be borne by ratepayers. How do you believe that the Commission should determine an appropriate discounting (reduction) or sharing of generation related costs associated with PECO's fossil and nuclear facilities?**

A. The determination of an appropriate discount factor to apply to the recovery of generation related stranded costs from ratepayers, using a just and reasonable standard, should be based, to the extent possible, on previous Commission precedents with respect to similar costs. In particular, the stranded generation costs at issue in this proceeding are associated with costs that are no longer used and useful (from an economic perspective) in a competitive market environment. There would appear to be no dispute in this regard. Although the legislation implementing retail competition in Pennsylvania envisions that utilities will experience such stranded generation costs, and that recovery of those costs (after mitigation) should be considered by the Commission, the clear implication of the legislation is that these costs are no longer used and useful in providing electric service. It is also clear that stranded costs (representing intangible costs) do not provide electric utility service in and of themselves. Rather, they represent a transition from a regulated to a competitive environment.

Given the nature of stranded generation costs and their relative comparability to generating costs that have previously been considered by the Commission as being not used and useful (for example, excess capacity), I believe that it is appropriate to consider a discount factor based on prior Commission remedies associated with the treatment of generating costs that have been found to be not used and useful. One such remedy that has been used by the Pennsylvania Public Utility Commission and other state commissions is the disallowance of an equity return on the investment associated with facilities that are found to be not used and useful. I believe that an equity return disallowance is an appropriate mechanism to adjust stranded generation costs for recovery from ratepayers through a CTC.

Q. Would you please provide specific citations in the Competition Act that support your recommendation that the Commission should only consider a just and reasonable level of generation stranded costs to be recovered from ratepayers through a CTC?

A. The first reference in the Act occurs in §2802(15), wherein the legislation states:

> **"The Commission is empowered under this chapter to determine the level of transition or stranded costs for each electric utility and to provide a mechanism, the competitive transition charge, for recovery of an appropriate amount of such costs in accordance with the standards established in this chapter."**

The Act requires the Commission to establish a CTC for stranded cost recovery based on the standards established subsequently in the Act. In particular, the standard that the Commission must use in approving a competitive transition charge is a just and reasonable standard. These standards are discussed in §2804 of the Act. Specifically, at §2804(13), the Act states as follows:

> **"The Commission has the power and <u>duty</u> to approve a competitive transition charge for the recovery of transition or stranded costs its determines to be just and reasonable to recovery from ratepayers."** (emphasis added)

Clearly, the Commission has a duty to utilize a just and reasonable standard in determining the amount of stranded costs to be recovered from ratepayers. Since other sections of the Act require the Commission to permit full recovery of stranded regulatory assets and non-utility generating project costs, the generation-related transition or stranded costs are the "costs" that must be adjusted in order to meet the just and reasonable recovery standard. In fact, the Act states at §2808(C) (3) that the Commission shall determine the level of generation-related transition stranded costs that may be recovered through the competitive transition charge.

Q. **Based on your understanding of the provisions of the Competition Act and the Commission's application of that Act in the QRO proceeding, does the Commission have a responsibility to apply the just and reasonable standard in the determination of the amount of generation-related stranded costs that may be recovered from ratepayers?**

A. Yes. I believe that some adjustment or discount from the total calculated level of stranded generation costs should be made prior to the calculation of the recovery of such costs through a CTC. The methodology that I am recommending in this proceeding is a reasonable approach to making such a stranded generation cost discount.

Q. How do you propose to incorporate an equity return disallowance into the development of a discount factor to be applied to generation related stranded costs?

A. A fair and reasonable methodology would eliminate the equity component of return on the unamortized balance of stranded generation costs, during the seven year transition period in which the CTC is recovered. As shown in Baron Exhibit ____(SJB-3), the methodology that I am proposing would use a rate of return, absent the equity component and corresponding income tax effects, applied to the total generation related stranded cost balance at the beginning of the CTC recovery period. Essentially, under the proposal that I am making, the discount on stranded cost (i.e., the removal of the equity return component), would only apply during the transition recovery period. <u>It would not penalize PECO for revenue requirements associated with the equity return component of rates over the entire remaining life of its generation assets</u>. Such an adjustment would result in a substantially greater discounting of generation costs.

Q. You mentioned in your previous answer that you are not proposing to disallow the equity return over the entire remaining life of PECO's generating assets, but only during the seven year transition period. Would you please explain this distinction in more detail?

A. As discussed by PAIEUG witness Falkenberg, we have adopted PECO's framework for computing stranded generation costs in this proceeding. Briefly, this methodology computes the present value of the margin associated with selling the kWh output of PECO's generating units over their remaining lives at market prices, compared to variable operating expenses. The present value of this margin for each generating unit equates to an estimate of the market value of PECO's generating units. In this respect, our approach is essentially the same as the methodology proposed by PECO. As noted by PECO in a data response, this is essentially the price at which PECO could sell its generating assets today, given market price assumptions.

The present value calculation that is equated to market value, is compared to the book value of the generating units. The difference is the loss that PECO would incur if it sold its generating assets at market prices.

Implicit in the PECO methodology is an assumption that its book value of generating assets is representative of the present value of the future stream of revenue requirements under regulation that PECO would otherwise recover from ratepayers. In this sense, the PECO methodology is an alternative way of performing a stranded cost analysis (and a preferred method in our view) from the methodology of comparing annual revenue requirements associated with each generating unit to revenues that could be achieved under market base pricing. Under the "annual revenue requirement versus market price" comparative methodology, an equity return and associated taxes is included in the computation of the annual revenue requirements associated with each generating unit. This equity return and tax gross-up would be included in the stranded cost calculation under this comparative revenue requirement methodology for each year of the remaining life of PECO's generating units. <u>If this equity return (and tax gross-up) were excluded, the reduction in stranded costs would be many times greater than the proposed discounting that I am recommending in this proceeding</u>.

In summary, I believe that the proposal to use a rate of return, exclusive of the equity return and associated tax gross-up, is an appropriate methodology to discount generation stranded costs for recovery from ratepayers through the CTC mechanism. Using the level of stranded generation costs developed by Mr. Falkenberg, the generation stranded cost discount that we are recommending in this proceeding is $473 million. The development of this discounting (or sharing between ratepayers and shareholders) can be seen by comparing the present value revenue requirements associated with stranded generation cost as computed in Baron Exhibit ____(SJB-3). This $473 million discount, represents 18% of our overall stranded cost calculation and is an equitable sharing of generation stranded costs.

<u>CTC Revenue Tracking Mechanism</u>

Q. **Would you please discuss your proposal for tracking CTC revenue collections to determine when the Company's stranded costs have been recovered from ratepayers?**

Q. This issue concerns the basic process that I believe should be adopted by the Commission to monitor and track CTC revenue collections from ratepayers to ensure that the Company is given a reasonable opportunity to recover its stranded costs over the seven year transition period. PECO states in its filing that such a CTC tracking mechanism should be implemented.

PAIEUG is recommending that the CTC component of PECO's unbundled rates be established as a residual, after subtracting transmission, distribution and estimated market prices from PECO's current bundled rates. As such, the CTC component of the Company's tariffs, which will <u>vary over the seven year period based on a fixed schedule,</u> does not correspond specifically to the total present value stranded cost revenue requirement that we are recommending in this proceeding (i.e., $2.21 billion). It is thus very critical under this methodology (a CTC residual methodology), to fully track CTC revenue accumulation over the transition period to determine when the Company has fully collected its stranded costs.

Q. What is your specific proposal regarding tracking CTC revenues?

A. The Company should accumulate, on a monthly basis, all CTC revenues produced by each rate schedule. These amounts should reduce the unamortized stranded cost balance each month. The unamortized stranded cost balance should accrue interest monthly at a fully grossed-up cost of capital (revenue requirement level). When the monthly stranded cost balance is fully amortized (i.e., the balance is $0), the CTC collection is terminated. It should be noted that the stranded cost revenue requirement recommended by PAIEUG already reflects the equity return disallowance and thus no further disallowance should be incorporated into the CTC tracking mechanism.

Q. Is it appropriate to track CTC revenues on a class-specific basis?

A. No. I believe that it is appropriate to aggregate, on a monthly basis, all CTC revenues produced by the Company's retail customers.

Q. **Under your proposed methodology, is it possible that PECO would not fully recover its authorized level of stranded costs within the seven year transition period?**

A. Although I do not believe that this will occur based on our recommended level of stranded costs, market prices and CTC charges, it is possible that the Company would not fully recover its allowed stranded costs (on a revenue requirement basis) over the seven year transition period. If this occurs, the Company should be permitted to file a request for an extension of the CTC recovery period beyond seven years. However, the Commission should not pre-approve such an extension of CTC recovery at this time. Rather, the Company's filing should stand on its own merits at the time it appears that the Company will not be able to achieve its authorized stranded cost recovery within a seven year period.

Q. **If the Commission ultimately approves an extension for the recovery of CTC costs from ratepayers beyond the seven year period, do you believe that it is appropriate to continue or extend the generation rate cap that will be in place during the first seven years of CTC recovery?**

A. Yes. Following the general framework of the Competition Act, I believe that it is absolutely appropriate, if not essential, that the generation rate cap be extended beyond seven years if the CTC recovery period is also extended beyond seven years. Clearly, the same rationale envisioned in the Competition Act for the establishment of a generation rate cap during the CTC recovery period of seven years would apply if the CTC recovery period is extended beyond seven years. Since consumers will be captive to the payment of the CTC, they should be afforded the protection of a generation rate cap during this period. Based on an analysis that I will discuss subsequently in my testimony, I believe that PECO will be able to recover the authorized level of stranded costs recommended by PAIEUG within the seven year time frame, using the rate design methodology that I am recommending in this proceeding.

<u>Appropriate Rate Design Methodology for CTC Development</u>

Q. **Would you please discuss the methodology that you are recommending for the development of the CTC component of each unbundled rate schedule?**

A. I am recommending that the CTC component of each unbundled rate be calculated as a residual, after removing transmission, distribution and estimated market prices from the current bundled rate. The estimated market prices would be the identical market prices used to develop the overall stranded generation costs (market value component). This methodology is in contrast to PECO's proposed unbundling wherein the Company removes transmission and distribution costs and then removes an allocated CTC revenue requirement from each rate schedule based on a fixed "production demand revenue requirement" assignment of overall stranded costs (on a levelized annual basis). Under PECO's methodology, the residual component of the unbundling process is a value that represents the market generation component of PECO's embedded cost-based rates, not the expected market price.

Q. **Under PECO's methodology for unbundling and CTC development, does the residual market generation rate reflect a realistic estimate of expected market prices in any given year?**

A. No. Since PECO's methodology calculates the market generation rate component of its bundled rate as a residual, there is no nexus between such a rate and the estimates utilized by PECO in developing its stranded costs. This occurs because the revenue requirements associated with stranded costs, on a levelized annual basis (approximately $1.3 billion based on PECO's calculations) are assigned to rate classes for recovery directly through an allocation process. Since these stranded costs represent an accumulated present value of stranded costs associated with the remaining lives of the Company's generating units, there is no reason to expect that the residual market prices produced under the Company's test year analysis would in fact represent a realistic level of market prices. In addition, since PECO's methodology begins with a levelized annual stranded cost revenue requirement, the resulting residual market prices embodied in the Company's unbundled rates are identical for each of the seven years of the CTC recovery period. This is clearly inconsistent with the assumptions that PECO itself is making with respect to market prices. (PECO is assuming that market prices increase over time, even during the first seven years of competition).

Q. Could you provide an example of how PECO's residual market generation rates are inconsistent with its own market price forecasts?

A. Yes. PECO has calculated unbundled generation rates for each of its rate schedules. Exhibit WFS-1, page 2 of 2 shows the unbundled generation rate (the residual market generation rate) for residential rate schedule R. The rate shown is 2.6388¢ per kWh for 0 to 500 kWh per month and 2.8345¢ per kWh for all kWh over 500 during the summer months. This market generation rate would remain constant for the entire seven year transition period under PECO's methodology.

Q. What is the expected market price assumed by PECO during the seven year period 1999 through 2005?

A. The composite capacity and energy prices paid to PECO's generators on a dollars per mWh basis ranges from $24.5 (2.45¢) in 1999 to $39.3 per mWh (3.93¢) per kWh in 2005. Clearly, PECO's market generation rate contained in the residential unbundled rate analysis is inconsistent with the assumptions that the Company is making with respect to market prices. In addition, in response to OCA data request II-7, PECO has calculated the residential market prices corresponding to its overall market price assumptions to range from 2.83¢ in 1999 to 4.43¢ 2005, (second block energy charge).

Q. What is the implication of this result for PECO's customers and alternative generation supplies?

A. The implications are significant with respect to possible detrimental impacts on the development of a competitive market during the transition period. Using the residential generation rate as an example, under PECO's unbundled rate results, residential customers would have to be able to obtain market prices from alternative generators during each of the seven years in the transition period that are lower than the generation component of the unbundled rate. Unfortunately, PECO's own forecast of market prices are substantially higher, in all but 1999, than the market generation rate component of is unbundled rate. As a result, residential customers would not effectively be able to access an alternative supplier. Similar results would occur for other rate classes, such as HT. By calculating the market generation component of its bundled rates as a residual, after removing transmission and distribution costs and allocated stranded costs, PECO has potentially established a rate structure that will deter a reasonable development of a competitive market in its region.

If customers cannot achieve savings by switching to alternative suppliers because PECO has a generation component of its unbundled rate at a level below market prices for six of the seven transition years, it seems reasonable to assume that alternative suppliers will simply not provide services in the PECO area. As a result, the development of a competitive market will be effectively undermined.

Q. **Do you believe that PECO's unbundling methodology is consistent with the intent of the Competition Act to promote the development of a competitive access market in Pennsylvania?**

A. No. As a result of the calculation of the generation component of PECO's unbundled rate as a residual, PECO has essentially established a below market generation component in its rates. As a result of the generation rate cap provision of the Competition Act, PECO cannot charge its customers market prices in excess of the embedded market generation rate calculated in its unbundling analysis. To the extent that this rate is lower than expected market prices (as I have previously demonstrated), PECO's methodology will act to deter an orderly development of competitive market in PECO's service area. The results of this methodology are detrimental to both PECO's customers and to alternative generation suppliers who may desire to sell competitively priced electricity to PECO's customers during the seven year transition period.

Q. **Is there an alternative methodology that could be used to unbundle PECO's rates?**

A. Yes. An alternative methodology is one proposed by PP&L in its restructuring proceeding and is similar to the methodology adopted by the Commission in its unbundling of rates for the pilot retail access program. Under this approach, embedded transmission and distribution costs are removed from the current bundled rate leaving a generation component. Thus far, the calculation is similar to the method recommended by PECO. At this point, however, PECO proposes to remove the allocated CTC from each rate schedule's bundled generation rate, leaving a residual component that "represents" the market generation component of the unbundled rate.

Under the alternative approach, which I am recommending, estimated market prices for each of the seven years would be subtracted from the unbundled generation component, leaving a residual value that would then become the CTC for each year. Since market prices change during the seven year transition period, increasing over time), the residual CTC would also vary (though fixed for each year at the time of unbundling) during the seven year period. Since market prices are increasing, while the total unbundled generation rate component remains constant, the CTC residual value each year would in fact decline. Under this approach, the market rate component of PECO's unbundled rate schedules would reflect expectations for market rates in each year of the transition period. As a result, if customers could obtain market rates at levels below the market generation rate component of PECO's unbundled rates in any given year, they would have an incentive to purchase power from an alternative supplier. This approach would result in an orderly development of a competitive market and provide opportunities for both customers and alternative generation suppliers to transact purchases and sales.

Utilizing this approach to rate unbundling would give PECO's customers an opportunity to actually participate in the market.

Q. Would you please summarize your recommendation regarding the appropriate rate design methodology to establish the CTC and unbundle the Company's rates?

A. I am recommending that each of PECO's current bundled rates be unbundled using a method that removes the embedded transmission and distribution rate component from the overall bundled rate to produce a generation rate component that is then further unbundled by subtracting expected market prices for each of the seven years during the transition period, leaving a residual value that becomes the CTC for the year. This is the methodology that has been proposed by PP&L (Docket No. R-00973954, PP&L Restructuring Filing) and one that will produce a reasonable opportunity for customers to actually participate in a competitive generation market.

Q. Have you determined whether the methodology that you are recommending for the development of the CTC will give PECO the opportunity to actually recover its stranded costs from ratepayers?

A. Yes. Using the methodology that I have just described, I have calculated the CTC revenues that will be produced by each of PECO's rate schedules during the transition period. Based on the analysis that I have performed, PECO would recover, on a present value basis, the entire stranded cost revenue requirement recommended by PAIEUG in this proceeding by May 2001. A summary of this analysis appears in Baron Exhibit ____(SJB-5).

IV. RATE DESIGN ISSUES

<u>Unbundling Methodology</u>

Q. Would you please discuss the specific methodology that you are recommending to unbundle PECO's rate schedules?

A. The basic methodology that I am recommending to unbundle PECO's rate schedules is similar computationally to the framework utilized by PECO. Beginning with the current bundled rates for each rate schedule, cost of service results are utilized to remove or unbundle the transmission and distribution components of the rate. The residual amount remaining in the bundled rate reflects the generation component of the rate and forms the generation rate cap under the Act.

At this stage, my proposal departs from PECO's unbundling recommendation. As I discussed previously, PECO has proposed to specifically allocate CTC revenue requirements to each rate schedule, and remove this amount from the generation portion of the bundled rate, leaving a "hypothetical market" rate component. This approach is inappropriate and should be modified so that "expected market prices" are directly incorporated into the unbundling analysis. The specific methodology that I am recommending explicitly establishes expected market prices for each of the seven years during the transition period, leaving a residual amount that forms the CTC.

Q. In your unbundling analysis, did you utilize the distribution and transmission costs that were developed by PECO?

A. With respect to the allocation of distribution and transmission costs to rate schedules for use in unbundling, I specifically adopted PECO's analysis and results. However, with respect to the HT rate schedule, there appears to be a significant over-assignment of costs to the distribution component of HT revenue requirements within the unbundling analysis (not the cost of service analysis).

It appears that PECO arbitrarily assigned 100% of administrative and general expenses and A&G plant to distribution and transmission costs in its functionalization analysis, while assigning no A&G expenses to the production portion of HT revenue requirements. Similar assignments were utilized by PECO in the development of all of its rate schedules, but my focus in this testimony is on the inappropriateness of such an assignment within the HT class. PECO has assigned A&G expenses to rate classes in its cost of service study primarily based on the total level of nonfuel operation and maintenance expenses assigned to each particular rate schedule. This is a reasonable approach for cost allocation and one that I do not dispute. In essence, for each rate schedule, such as Rate HT, the summation of nonfuel O&M expenses for distribution, transmission and production (generation) is used to assign the total PECO A&G expense to the HT rate schedule. Obviously, under the Company's cost of service method, the amount of A&G expense assigned to the HT rate schedule is a function of the <u>amount of production O&M expenses assigned to HT</u>. However, in its calculation of functional HT revenue requirements (i.e., HT distribution revenue requirements, HT transmission revenue requirements and HT production revenue requirements), PECO arbitrarily assigns <u>all of the A&G expense to the distribution and transmission</u> function, while assigning none of these costs to production.

Q. What is the main impact of this arbitrary assignment of A&G expenses by PECO within rate schedule HT?

A. The main impact is to substantially increase the distribution unit costs and thus the distribution unbundled rate in the HT Schedule. HT customers take service at voltages ranging from 13.2 kV to 69 kV and above. A relatively small portion of the overall HT rate schedule revenue requirements are comprised of distribution costs. However, because of PECO's arbitrary assignment of A&G expenses to the distribution revenue requirements for HT, the unbundled distribution rate for rate HT is substantially greater than it should be. Obviously, in a competitive environment, where customers will continue to purchase distribution services from PECO, this makes sense, if you are a monopoly supplier. However, there is no justification for this arbitrary assignment that simply takes advantage of captive customers. Unbundled distribution rates, as well as other unbundled rate components should be based on cost and not arbitrary cost assignments that are only made possible because customers cannot competitively choose their distribution suppliers.

Q. How have you addressed this problem in your HT unbundling analysis?

A. I employed the same cost causation principles utilized by PECO in its cost of service study in my unbundling analysis. The correct methodology to assign HT A&G expenses to distribution, transmission and production functions is the cost-based method utilized by PECO to assign A&G costs to rate schedules in its filed cost study. This is the methodology that I employed and is totally consistent from a cost of service basis with PECO's own study.

Q. Does this adjustment to the HT unbundling analysis have any impact on any other rate schedule?

A. No. Although theoretically, this change, if applied to all rate classes, would have a slight impact on the allocation of transmission cost to each rate schedule, I ignored this change so that the HT unbundling adjustment that I am recommending would have no interclass rate design impact. No other rate schedules cost or rate unbundling is affected by this change to rate schedule HT. Of course, it would certainly be appropriate to implement this correction of the assignment of A&G expenses for other rate classes as well. Finally, PECO's proposed A&G expense methodology would violate the prohibition against intraclass cost shifts contained in the Competition Act.

Q. Would you please discuss the market prices that you employed for each of the seven years during the transition period in your unbundling analysis?

A. The expected market prices, both capacity and energy, employed in our unbundling analysis are derived from the identical market prices calculated by PAIEUG witness Falkenberg and used in our stranded generation cost market value analysis. Mr. Falkenberg has calculated hourly marginal costs and annual capacity prices for each year of his analysis. In order to utilize these hourly market clearing energy prices and annual capacity values to develop market rates for each rate schedule, annual energy prices have been calculated for on- and off-peak periods for each of the seven transition years. Baron Exhibit ____(SJB-6) summarizes the on- and off-peak energy prices and annual capacity values derived from Mr. Falkenberg's market price forecast.

Q. How were these on- and off-peak energy prices and annual capacity values utilized to develop market prices for each rate schedule?

A. In response to OCA Data Request II-7, PECO provided on- and off-peak kWh for each major rate schedule during the 1996 test year. Using these kWh values, I calculated weighted average market prices for energy for each rate schedule. For rate schedules OP, SLP, SLS and SLE that are assumed to be off-peak only by PECO, I assumed that only the off-peak market energy rates would apply. For rates EP, PD and interdepartmental an average on-peak/off-peak ratio was calculated such that the total of all PECO rates conformed to the total on- and off-peak energy mix of the Company.

Q. How is the annual capacity value assigned to a rate schedule and used to produce an unbundled market price?

A. Following PECO's cost allocation method, I employed each classes' four CP demand for the test year, adjusted for losses and an 18% reserve margin to determine the total amount of capacity that would be required to meet each customer classes' load, for each year of the analysis. It should be noted, that throughout this seven year transition period, no load growth was assumed in the rate design analysis. This is essentially the same assumption that PECO employed, and, of course, to the extent that there is load growth, it would be recognized by an acceleration in CTC revenue recovery.

Once the total required capacity mWs has been computed, a total capacity revenue requirement can be developed by multiplying this load value by the market capacity rate shown in Baron Exhibit ____(SJB-6) for each of the seven transition years. This capacity revenue requirement is then utilized in the unbundling analysis by developing a capacity component of the market price. For rate schedules, such as residential, where there is no demand charge in the tariff, the capacity revenue requirements are simply unitized by total kWh sales. For rate schedules such as HT, where specific demand charges are part of the tariff, the market capacity revenue requirements are unitized by billing demand to produce a market demand charge.

Energy rates are adjusted by each class's energy loss factor to produce the market energy rate (average annual value) for each year of the seven year transition period.

Q. **Have you prepared specific unbundling analyses of PECO's rate schedules?**

A. Yes. For presentation purposes, I have developed exhibits that illustrate the unbundling analysis that I am recommending for the residential class (rate R) and rate schedule HT, the large industrial rate.

Baron Exhibit ___(SJB-7), pages 1 and 2 show the residential unbundling analysis following the methodology that I have previously described. It should be noted that the unbundled distribution and transmission rates in Baron Exhibit ___(SJB-7), the PAIEUG recommended analysis, are essentially identical to PECO's proposed residential unbundled rates for distribution and transmission. As I indicated, I have not modified these components for any rate schedule except rate schedule HT. The market generation rate for energy is assumed to be flat for all rate blocks of the rate. This reflects the fact that no such blocking would actually occur in a competitive market.

Page 1 of Baron Exhibit ___(SJB-7) shows the specific unbundled transmission, distribution and embedded generation rate.

Page 2 of Baron Exhibit ___(SJB-7) shows the development of the market prices for the residential rate schedule, beginning with the on- and off-peak energy rates for each year of the transition period and the annual capacity market clearing price. For residential customers, the resulting average annual market rate beginning in 1999 is 3.6¢ per kWh. By the year 2005, this market price for residential customers would increase to 5.1¢ per kWh. Again, these are the market prices assumed by PAIEUG in our stranded generation cost analysis in which we calculate the market prices paid to PECO's generators.

Once again, because market prices vary each year, while the embedded generation rate component (the rate cap) of rate schedule R remains constant, the resulting residual CTC declines each year during the transition period. It also should be noted that the CTC charge is fixed for each of the seven years at the time of unbundling and would not change if actual future market prices differed from expected market prices used in the analysis. It would be totally inconsistent to modify the market prices each year to reflect actual values and thus modify the CTC, while not modifying the overall stranded cost calculation. Since the stranded cost calculation will not be modified, it is not appropriate to modify any of the elements of the unbundled rate for any of the seven transition years.

Q. **Would you present the results of your unbundling analysis for rate schedule HT?**

A. Baron Exhibit ____(SJB-8), pages 1 and 2 show the unbundling analysis for rate schedule HT. Following the same methodology described for the residential class, market energy prices and capacity values are converted into an overall market demand and energy rate for rate schedule HT. This is shown on Page 2 of the exhibit. Page 1 shows the initial unbundling analysis, including the unbundling of distribution and transmission charges. The distribution unbundling analysis is based on a modification of the distribution revenue requirements for rate schedule HT that reflects the removal of the inappropriately assigned A&G expenses, as previously discussed.[2] Finally, as can be seen from page 2 of Baron Exhibit ____(SJB-8), the HT unbundling analysis that I am recommending continues to rely on PECO's blocking (i.e., rate blocks) from the Rate HT Schedule. This is necessary to preserve intraclass cost allocation. As a result, except for the market prices, all other unbundled rate components reflect the same type of unbundling analysis by rate block recommended by PECO in its proposal.

Q. Do you recommend that similar methodologies be employed to unbundle all of PECO's rate schedules?

A. Yes. Although I have only illustrated in this testimony the analyses for the residential and HT classes, similar analyses have been performed for each rate schedule. Again, in all cases, I have continued to use the same distribution and transmission unbundling analysis developed by PECO (for these other rate schedules) and have only modified the generation portion of the unbundled rate, relative to the PECO proposal. Utilizing the same market prices as shown for the residential and HT classes, each rate schedule has been unbundled to produce a market price for each of the seven transition years and a corresponding CTC value.

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[2] In order to maintain PECO's proposed transmission cost allocation among rate classes, no change was made to the HT transmission rate. The A&G costs removed from the HT distribution charge were properly shifted to the generation component of the rate.

<u>Rate Design Issues Associated with Large Industrial Load Rider ("LILR") Customers and EER Customers</u>

Q. Would you please briefly describe the arrangement utilized by LILR customers to purchase electricity from PECO?

A. These customers represent large industrial customers who are willing to be interrupted by PECO. While subjecting themselves to the potential for complete interruption, these customers purchase supplemental energy at PJM market rates plus 10 mills per kWh (1¢). During the off-peak period, LILR customers purchase energy from rate schedule HT, although this energy would be almost at all the HT "tail-block" rate, since there is minimal on-peak HT billing demand for most customers. In addition, LILR customers also pay a demand charge associated with their maximum off-peak kW demands.

Q. Given the fact that LILR customers purchase all of their energy during the on-peak hours at market PJM rates plus 1¢ and are subject to interruption in all hours, is it appropriate to assign any stranded cost to the <u>supplemental energy</u> portion of LILR customer load?

A. No. LILR customers are currently paying market energy rates during the on-peak period (plus a 1¢ margin per kWh). Transition to competition would not impose stranded cost since both current and future rates are both based on market prices. PECO does not provide generation facilities for such supplemental energy purchases at PJM market rates.

Q. PECO has effectively stated in its testimony that if an LILR customer should leave the PECO system and seek an alternative generation supplier, then such an LILR customer would not be permitted to take service on an unbundled LILR rate for the purposes of paying distribution, transmission <u>and</u> a competitive transition charge. Is this a reasonable position?

A. Absolutely not. If, for example, LILR customers were forced to pay an HT rate CTC based on kWh usage previously associated with the prior supplemental energy purchases (PJM market rates plus 1¢), the resulting CTC, coupled with market rates from alternative suppliers would greatly exceed the existing LILR rates paid by these customers and essentially eliminate the possibility that such a customer could seek alternative generation. Such treatment would produce an intraclass cost shift to LILR customers. This is particularly problematic since LILR customers on the PECO system tend to be among the largest customers served by PECO. As a result, PECO's most energy-intensive and largest customers would be foreclosed from accessing the competitive market during the seven year transition period, under PECO's proposal.

Q. Does PECO provide any support for its position that LILR customers should revert to HT rates status, if they leave the PECO system and seek alternative generation suppliers?

A. No. PECO simply asserts that the LILR rate, being interruptible, is inextricably tied to PECO's generation system and thus, if such a customer leaves there would be no reason to continue offering LILR service. <u>There is absolutely no support for the apparent position of PECO that an LILR customer should pay stranded costs as though such a customer had been a firm HT customer all along</u>. There is no support in PECO's argument for this drastic policy position. The fact that an LILR customer may no longer be interruptible after leaving PECO's system does not change the fact that such a customer only purchased PJM market energy during the on-peak hours over the years when the LILR customer did take service from PECO.

Q. How should LILR customers be charged for stranded cost (and a CTC) if they seek alternative generation suppliers?

A. First of all, PECO has indicated that it intends to unbundle the LILR rate prior to January 1, 1999. Unfortunately, LILR customers cannot wait until January 1999 to evaluate the alternatives available to them in a competitive market. These customers must know, with certainty, the types of costs they would face under alternative decision making regarding remaining a PECO LILR customer and seeking alternative generation suppliers.

From a cost-causation standpoint, LILR customers should not be responsible for a CTC charge on past <u>supplemental energy purchases</u> that these customers made at PJM market rates. However, an LILR customer should be responsible for the CTC associated with its HT usage. To the extent that an LILR customer pays HT on-peak billing demand charges and HT hours use energy charges (principally in the tail-block of the HT rate), such a customer should be responsible for the CTC approved by the Commission for those rate elements. In addition, it is appropriate to charge LILR customers (or any interruptible customer) the unbundled distribution and transmission charges (assuming such a customer does not elect the FERC tariff) associated with HT usage, if such an LILR customer actually leaves the PECO generation system and purchases alternative generation supplies. As a distribution and transmission customer, the LILR customer usage would be billed at the unbundled distribution and transmission rates approved by the Commission for rate schedule HT. However, as I indicated above, only the historical level of "HT usage" should (and <u>not</u>

supplemental energy) be considered in applying a CTC charge to LILR customers who purchase alternative generation.

Q. Would you please explain how your proposal would work in practice for LILR customers who chose alternative suppliers?

A. Following PECO's proposal in other rate design areas, it is reasonable to develop an historic test year level of LILR usage based on 1996 data (or a prior 12 month period from the time that the customer leaves the PECO system) to determine the percentage of total usage (demand and energy) that was historically associated with LILR on-peak supplemental energy purchases and the percentage of usage associated with LILR off-peak HT usage. This on-peak/off-peak factor would then be applied to an LILR customer's future usage, assuming that such a customer purchased its energy from an alternative supplier, to determine the amount of CTC charges that can be attributed to that customer's HT usage historically. The amount of HT energy calculated (by applying the historical off-peak usage factor to prospective usage) would determine the amount of CTC charges associated with the LILR customer's HT responsibility. The CTC charge would be calculated using the unbundled HT rate schedule in a manner identical to an LILR customer's charges for off-peak LILR energy on rate HT today (prior to unbundling).[3]

Q. How would you compute the amount of distribution and transmission charges associated with an LILR customer's usage, assuming such a customer purchased generation from an alternative supplier?

A. It is appropriate to utilize the full energy and demand of an LILR customer (if the customer purchases from an alternative supplier) in computing the unbundled HT distribution and transmission charges. Essentially, for these two components of cost (distribution and transmission), I would agree that an LILR customer who leaves the PECO system should pay T&D charges similar to a firm customer who has historically been an HT customer, unless the customer purchases directly from the FERC-approved PJM transmission tariff.

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[3] For example, assume an LILR customer used a total of 3000 mWh per month during the test year (a recent 12 month period), and had an HT billing demand of 250 kW with 33% of the energy classified as on-peak (and billed at the PJM rate plus 1¢) and 67% billed on rate schedule HT. In this case, 67% of the energy (kWh) prospectively would be billed on rate schedule HT to calculate the applicable CTC. This 67% of a customers' prospective monthly energy (after leaving the PECo system) should be assigned to HT hours-use rate blocks in the same percentage ratio as the such customer's historic HT energy use had been billed during the test year. At a 250 Kw HT billing demand and 2000 mWh of HT energy (67% of 3000 mWh), 1.875% would have been billed in HT energy block 1, 1.875% in HT energy block 2 and 96.25% in the HT tail block. If the HT billing demand had been higher, more of the 2000 mWh would have been billed in the first two blocks. Finally, the historic HT billing demand for the test year (a minimum of 25 kW for LILR customers) should be used to calculate the CTC associated with an LILR customer's firm billing demand.

Q. Do you have a similar recommendation for customers who are currently under longer term contracts and are classified as EER customers?

A. Yes. For an EER customer, the Company should perform an unbundling analysis in a similar manner to that which I am recommending for rate schedule HT. If an EER customer leaves the PECO system and seeks alternative generation supplies, such an EER customer should pay the appropriate unbundled transmission and distribution charges associated with the customer's specific EER rate and a CTC charge, following the identical methodology that I am recommending for rate schedule HT (i.e., removing a market price value for each of the seven transition years from the generation portion of the unbundled EER rate, leaving a residual value to be established as the CTC for the EER rate).

It is entirely inappropriate, to charge an EER customer unbundled transmission and distribution costs and a CTC based on the full firm HT rate. An intraclass cost shift would occur if such EER customers were charged the full HT T&D and CTC charges, in the event that an EER customer leaves the PECO system for alternative generation supplies. This is clearly inappropriate and anticompetitive. In order to meet the rate cap provisions of the Competition Act and to encourage a reasonable development of the competitive market, PECO must unbundle each EER rate in an identical fashion to the unbundling approved by the Commission for rate schedule HT.

Transmission Rate Design Issues

Q. Do you have any comments on PECO's proposed transmission rate design and its HT transmission rate unbundling analysis?

A. Yes. In general, PECO's approach of using the PJM FERC Order No. 888 transmission revenue requirement is appropriate for the initial transmission rate unbundling analysis associated with rate schedule HT. However, as indicated by PECO, large customers may wish to directly access transmission service rates under the PJM FERC Order 888 tariff. If such a customer elects to take service directly under the FERC tariff, I would not expect that the T&D rate cap protection would apply to any additional ancillary service costs that may be imposed on the customer for usage of various service components.

However, if the customer chooses or elects an alternative generation supplier and continues to purchase delivery service from PECO, then at least for the 54 month "T&D" rate cap period through June 2001, there should be no additional ancillary service charges imposed on such customers. This issue is somewhat unclear in

PECO's testimony and I simply wish to state the PAIEUG position that it is inappropriate to include any additional ancillary service costs in this scenario. Clearly, it would be a violation of the T&D rate cap provision to charge additional ancillary service costs to a customer who utilizes PECO's delivery service for their purchases of alternative generation supplies. These ancillary services are already provided in the current bundled service rate.

Q. The HT class includes customers served at voltages as low as 13.2 kV and as high as 69 kV or greater. Does PECO make any distinction among such customers with respect to delivery charges?

A. The HT rate includes a very small discount if a customer takes service at 69 kV or above. This discount does not reflect a cost-based differential between customers who are essentially transmission voltage customers and customers who are primary service customers.

Q. Has PECO considered this voltage differentiation issue (in terms of losses and facilities charges) in its distribution rate unbundling analysis for rate schedule HT?

A. No. As a result, if a high voltage (e.g, 69 kV or above) HT customer leaves the PECO system, chooses an alternative generation provider, and elects to purchase transmission services directly from the FERC Order No. 888 tariff, such a customer would continue to be charged a distribution delivery charge, even though such a customer is not using distribution facilities (except perhaps metering and some service line facilities). Clearly, a customer taking service at 69 kV or above is not using transformation and primary distribution line facilities associated with providing 13.2 kV service. As a result, such a customer would be at a competitive disadvantage compared to customers on other Pennsylvania electric utilities in which primary service costs are more fully unbundled within and between tariffs.

Q. **What is your recommendation to the Commission to address this problem?**

A. I believe that it would be appropriate for PECO to further unbundle its distribution delivery charge within rate schedule HT. It would be appropriate for PECO to develop separate distribution rates associated with HT customers taking service at various service voltages. Given the broad range of customer characteristics within the HT class, this is a reasonable recommendation and one which would lead to a more competitively priced delivery service from PECO, compared to other Pennsylvania utilities. Where there is a legitimate cost basis for including certain facilities in the distribution delivery charge, it is appropriate to do so. However, given the shift to a competitive electric rate environment, it is not appropriate to continue utilizing a bundled distribution delivery rate for all types of HT customers. Essentially, PECO should be required to further unbundle its distribution cost to remove any costs that may be applicable to high voltage service so that such a customer will not pay for other distribution costs associated with facilities not required to serve such high voltage customers. This of course, would apply to both regular HT, LILR, and EER customers.

<u>On-Site Generation Issues</u>

Q. How has PECO proposed to treat customers who elect to install on-site generation, with respect to CTC charges?

A. PECO has proposed a "test" that would flag customers whose usage drops by 10% or more in a calendar year from a prior base period as a means of identifying customers who install self-generation and whose usage drops as a result. Such customers, would be charged a CTC charge associated with the lost sales (now provided for by on-site generation) based on using a 12 month test year for comparison purposes.

Q. Do you believe that PECO's proposal meets the requirements of § 2808 of the Act, with respect to on-site generation?

A. No. §2808(A) addresses this issue. The Act states as follows:

> **"If a customer installs on-site generation which operates in parallel with other generation on the public utility's system and which <u>significantly</u> reduces the customer's purchases of electricity through the transmission and distribution network, the customer's fully allocated share of transition or stranded cost shall be recovered from the customer through a competitive transition charge."** (§2808(A), <u>emphasis added</u>).

The question at issue regarding PECO's proposed treatment of on-site generation is whether a 10% reduction in a test year level of usage for a specific customer represents a "significant" reduction in purchases of electricity. I believe that a more reasonable threshold would be a 25% reduction criterion rather than PECO's proposed 10% level. As a policy matter, it does not appear to be reasonable to utilize a 10% change in a customer's level of usage as representative of a significant change in usage.

Selection of Customers for Participation in the Phase-In of Retail Access

Q. Under the proposed phase-in plan for participation in retail access, 33% of PECO's retail load would be eligible for participation beginning January 1, 1999, with a second phase to include 66% of all retail load beginning on January 1, 2000. How should customers be selected for participation from each rate schedule?

A. The most appropriate methodology for selecting large customers on rate schedule HT (including LILR and EER customers), is a "first come, first served" basis, with the customer designating a desired level of load for participation in direct access. For each phase-in period, PECO should select HT customers on the basis of a first come, first served approach unless and until there is an over-subscription of load for each phase.

Q. What is your recommendation if such an over-subscription to any phase-in load level occurs?

A. If, for a specific rate class, there is an over-subscription of customer-nominated loads based on a first come, first served selection, there should be a pro-rata reduction to each subscriber's nominated load amount, such that the total load available for that rate class meets the requirements of the Act. Thus, if all customers in a class nominate 100% of their load, all customers are assured of at least 33% of their load for participation.

Q. Could this first come, first served selection process, coupled with a pro-rata reduction, in the case of over-subscriptions, still produce problems for some large industrial and commercial customers who receive less than 100% of their nomination.

A. Yes, but the Commission can help alleviate these problems by requiring PECO to begin the next phase of its selection one day (January 2, 1999) following the selection for the first phase. Under the Competition Act, PECO is required to complete its second phase by January 1, 2000. It can begin selection of the second phase and actually implement such a selection process by permitting retail access for 66% of peak load beginning on January 2, 1999. A similar adjustment can be made to the second phase such that on January 2, 2000, all remaining customers can be selected for participation in the retail access program. The Commission should adopt this proposal as a methodology to deal with such contingencies.

Q. **Does that complete your testimony?**

A. Yes, it does.

PAIEUG STATEMENT NO. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

JUNE 1997

Expert Testimony Appearances of Stephen J. Baron As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates,excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co.	Analysis of South Central Bell's restructuring and and proposed merger with Southern Bell Telephone Co.
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger of GSU into Entergy System; impact on system agreement.
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 1997

Date	Case	Jurisdict.	Party	Utility	Subject
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.

**Expert Testimony Appearances
of
Stephen J. Baron
As of June 1997**

Date	Case	Jurisdict.	Party	Utility	Subject
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bankruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan analysis of rate paths produced by competing plans.

PECO ENERGY COMPANY
PAIEUG Recommended Stranded Costs
($000)

Net Generating Plant & CWIP	6,688,384
Less: PAIEUG Market Value	4,811,327
Stranded Plant	1,877,057
Less: Equity Return Disallowance	-472,822
Regulatory Assets, Decommissioning, Other	805,177
Total Stranded Costs	**2,209,412**

REVENUE REQUIREMENT

Year	Beginning Unamortized Stranded Cost Balance	Return @ 12.35%	Annual Amortization	Total Annual Rev Req	PV of Annual Rev Req
1999	2,209,412	254,996	315,630	570,627	549,118
2000	1,893,782	216,016	315,630	531,646	476,040
2001	1,578,152	177,036	315,630	492,666	410,472
2002	1,262,521	138,055	315,630	453,686	351,721
2003	946,891	99,075	315,630	414,705	299,156
2004	631,261	60,095	315,630	375,725	252,202
2005	315,630	21,114	315,630	336,745	210,332

Total PV of Stranded Costs Rev Req	2,549,041
Levelized Annual Rev Req w/GRT	486,516

PECO ENERGY COMPANY
Stranded Generation "Sharing" Analysis
PAIEUG Calculation
Monthly Amortization with end-of-period convention
No Equity Return on Stranded Plant
($000)

Net Generating Plant & CWIP	6,688,384
Less: PAIEUG Market Value	4,811,327
Stranded Plant	1,877,057

Year	Beginning Unamortized Stranded Plant Balance	Return @ 3.96%	Annual Amortization	Total Annual Rev Req	PV of Annual Rev Req
1999	1,877,057	69,465	268,151	337,616	324,818
2000	1,608,906	58,846	268,151	326,997	292,724
2001	1,340,755	48,227	268,151	316,378	263,523
2002	1,072,604	37,608	268,151	305,759	236,968
2003	804,453	26,989	268,151	295,140	212,832
2004	536,302	16,371	268,151	284,522	190,907
2005	268,151	5,752	268,151	273,903	171,002

Total PV of Stranded Costs Rev Req - No Equity Return	1,692,775
Total PV of Stranded Costs Rev Req - Full Rate of Return [1]	2,165,597
Equity Return Revenue Requirement	(472,822)

[1] From Exhibit ___ (SJB-3), page 2 of 2

PECO ENERGY COMPANY
Stranded Generation "Sharing" Analysis
PAIEUG Calculation
Monthly Amortization with end-of-period convention
Full Equity Return on Stranded Plant
($000)

Net Generating Plant & CWIP	6,688,384
Less: PAIEUG Market Value	4,811,327
Stranded Plant	1,877,057

Year	Beginning Unamortized Stranded Plant Balance	Return @ 12.35%	Annual Amortization	Total Annual Rev Req	PV of Annual Rev Req
1999	1,877,057	216,638	268,151	484,789	466,516
2000	1,608,906	183,521	268,151	451,672	404,431
2001	1,340,755	150,405	268,151	418,556	348,726
2002	1,072,604	117,288	268,151	385,439	298,813
2003	804,453	84,171	268,151	352,322	254,155
2004	536,302	51,055	268,151	319,206	214,264
2005	268,151	17,938	268,151	286,089	178,692

Total PV of Stranded Costs Rev Req - Full Rate of Return 2,165,597

PECO Energy Company
Calculation of Adjusted Rate of Return

	Amount	Weight	Cost Rate	Weighted Cost	Pre-Tax Cost	Pre-Tax no CE Return
Debt	4,218	44.6%	7.47%	3.33%	3.33%	3.33%
MIP	302	3.2%	9.21%	0.29%	0.29%	0.29%
Preferred	292	3.1%	6.37%	0.20%	0.34%	0.34%
Common	4,644	49.1%	10.00%	4.91%	8.39%	
Total	9,456	100.0%		8.73%	12.35%	3.96%
Tax Shield				-1.50%		
After-tax weighted cost of capital				7.23%		

COST OF CAPITAL PER PECO					
Debt	4,218	44.6%	7.47%	3.33%	3.33%
MIP	302	3.2%	9.21%	0.29%	0.29%
Preferred	292	3.1%	6.37%	0.20%	0.34%
Common	4,644	49.1%	11.60%	5.70%	9.74%
Total	9,456	100.0%		9.52%	13.70%
Tax Shield				-1.50%	
After-tax COC				8.02%	

Composite Tax Rate 41.493%

PECO ENERGY COMPANY

Summary of CTC Tracking Mechanism

PAIEUG Recommended CTC and Stranded Costs Revenue Requirements [1]

Monthly Calculations for Collection and Interest [2]

Rate Class	1999	2000	2001	2002	2003	2004	2005
HT	423,523	384,391	130,757	0	0	0	0
EP	13,053	10,961	3,446	0	0	0	0
PD	34,214	30,242	10,100	0	0	0	0
GS	312,935	288,889	100,037	0	0	0	0
RH	72,056	63,956	21,601	0	0	0	0
R	291,479	263,622	88,518	0	0	0	0
OP [3]	0	0	0	0	0	0	0
SLP [3]	1,524	0	0	0	0	0	0
SLS [3]	928	0	0	0	0	0	0
SLE [3]	707	0	0	0	0	0	0
OTHER [3]	66	0	0	0	0	0	0
TOTAL	1,150,486	1,042,062	354,460	0	0	0	0
Beginning Balance	2,209,412	1,280,135	344,377	0	0	0	0
Return	221,208	106,304	10,083	0	0	0	0
Collection	-1,150,486	-1,042,062	-354,460	0	0	0	0
Ending Balance	1,280,135	344,377	0	0	0	0	0

[1] Revenues collected net of Gross Receipts Tax

[2] Recovery from each rate schedule is assumed to occur in equal monthly amounts each year

[3] Pro-rata responsibility based on Fixed Production Revenue Requirement credited in initial period

Exhibit ___ (SJB-5)

PECO ENERGY COMPANY
PAIEUG Load-weighted Market Prices

		1999	2000	2001	2002	2003	2004	2005
Market Demand Price	$/kW/year	24.17	30.82	46.50	49.05	53.43	58.16	59.97
Market Energy Prices [1]								
On-peak	$/mWh	32.65	35.41	36.33	36.74	38.60	36.80	39.54
Off-peak	$/mWh	21.54	22.61	23.05	23.22	24.09	23.47	24.74
Average	$/mWh	25.81	27.53	28.15	28.41	29.66	28.59	30.42

[1] Load weighted averages based on PAIEUG hourly PJM market clearing prices and PECO 1994 EEI Load Deck
On-peak hours defined as 8 a.m. to 8 p.m., Monday through Thursday, 8 a.m. to 4 p.m. Friday, no holidays.

Exhibit ___ (SJB-6)

PECO ENERGY COMPANY
Unbundling Analysis
Rate R

Revenue Requirement	Revenue Requirement	Less: Fixed	Rev Req for Unbundling
Transmission	39,022,224		39,022,224
Distribution	474,416,000	(69,921,244)	404,494,756
Average Embedded Energy Cost	0.01415		

	Adjusted Units	Present Rate	Rates less Energy	Revenue	%
1. Customer Charge	13,710,048	5.10	5.10	69,921,244	
2. Up to 500 kwh	5,355,673,018	0.130500	0.116352	623,141,563	67.884%
3. kwh over 500-Winter	1,245,582,498	0.130500	0.116352	144,925,618	15.788%
4. kwh over 500-Summer	1,110,656,685	0.149100	0.134952	149,884,987	16.328%
				917,952,169	100.000%

	Transmission Revenue	Transmission Price	Distribution Revenue	Distribution Price
2. Up to 500 kwh	26,489,801	0.004946	274,586,741	0.051270
3. kwh over 500-Winter	6,160,800	0.004946	63,861,337	0.051270
4. kwh over 500-Summer	6,371,623	0.005737	66,046,678	0.059466
TOTAL	39,022,224		404,494,756	

Embedded Generation Rate Cap
0.074284
0.074284
0.083897

Exhibit ___ (SJB-7)

PECO ENERGY COMPANY
Unbundling Analysis
Rate R

	1999	2000	2001	2002	2003	2004	2005
Market Demand Price	24.17	30.82	46.50	49.05	53.43	58.16	59.97
Market Energy Prices							
On-Peak	32.65	35.41	36.33	36.74	38.60	36.80	39.54
Off-Peak	21.54	22.61	23.05	23.22	24.09	23.47	24.74
On-Peak Energy weight	0.3512						
Off-Peak Energy weight	0.6488						
Energy at Meter	7,699,431						
Energy at Generation	8,493,499						
Energy Loss Factor	0.90651						
Avg 4CP Demand	1,750,693						
Reserve Margin	18%						
Gross Receipts Tax Rate	4.4%						
Market Generation Cost							
Demand	52,233,021	66,602,909	100,473,321	105,983,706	115,451,378	125,681,658	129,590,357
Market Demand Rate [1]	0.006773	0.008636	0.013028	0.013743	0.014971	0.016297	0.016804
Market Energy Rate [2]	0.029360	0.031275	0.031980	0.032271	0.033674	0.032483	0.034542
Market Generation Rate	0.036133	0.039911	0.045008	0.046014	0.048644	0.048780	0.051346
CTC Rates							
2. Up to 500 kwh	0.038151	0.034373	0.029275	0.028270	0.025639	0.025503	0.022937
3. kwh over 500-Winter	0.038151	0.034373	0.029275	0.028270	0.025639	0.025503	0.022937
4. kwh over 500-Summer	0.047764	0.043986	0.038889	0.037883	0.035253	0.035117	0.032551
Estimated CTC Revenues	304,894,595	275,755,559	236,445,786	228,688,957	208,405,010	207,357,162	187,567,635
Less: GRT	-13,415,362	-12,133,245	-10,403,615	-10,062,314	-9,169,820	-9,123,715	-8,252,976
CTC Revenues w/o GRT	291,479,233	263,622,314	226,042,171	218,626,642	199,235,190	198,233,447	179,314,659

[1] Market Demand Cost unitized by adjusted sample billing determinants

[2] Weighted Average Market Energy price adjusted for losses and GRT

Exhibit ___ (SJB-7)

PECO ENERGY COMPANY
Unbundling Analysis
Rate HT

Revenue Requirement	Revenue Requirement	Distribution Adjustment	Less: Fixed	Rev Req for Unbundling
Transmission	60,096,358			60,096,358
Distribution	130,548,000	(77,205,000)	(8,536,697)	44,806,303
Average Embedded Energy Cost		0.01353		

	Adjusted Units	Present Rate	Rates less Energy	Revenue	%
1. Customer Charge	27,762	286.86	286.86	7,963,827	
2. All KW	24,911,867	12.76	12.76	317,875,423	40.352%
3. Kwh-First 150 Hrs	3,730,248,598	0.082900	0.069370	258,767,381	32.849%
4. Kwh-Next 150 Hrs	3,640,776,279	0.055000	0.041470	150,983,027	19.166%
5. Kwh-Addl Use	4,334,660,758	0.027400	0.013870	60,121,787	7.632%
				787,747,618	100.000%

	Transmission		Distribution		
	Revenue	Price	Revenue	Price	Embedded Generation Rate Cap
2. All KW	24,250,350	0.97345	18,080,439	0.72578	11.06078
3. Kwh-First 150 Hrs	19,741,065	0.005292	14,718,432	0.003946	0.073662
4. Kwh-Next 150 Hrs	11,518,321	0.003164	8,587,765	0.002359	0.049478
5. Kwh-Addl Use	4,586,622	0.001058	3,419,668	0.000789	0.025553
TOTAL	60,096,358		44,806,303		

Exhibit __ (SJB-8)

PECO ENERGY COMPANY
Unbundling Analysis
Rate HT

	1999	2000	2001	2002	2003	2004	2005
Market Demand Price	24.17	30.82	46.50	49.05	53.43	58.16	59.97
Market Energy Price	25.81	27.53	28.15	28.41	29.66	28.59	30.42
On-Peak	32.65	35.41	36.33	36.74	38.60	36.80	39.54
Off-Peak	21.54	22.61	23.05	23.22	24.09	23.47	24.74
On-Peak Energy weight	0.3880						
Off-Peak Energy weight	0.6120						
Energy at Meter	13,229,869						
Energy at Generation	13,754,655						
Energy Loss Factor	0.96185						
Avg 4CP Demand	2,316,073						
Reserve Margin	18%						
Gross Receipts Tax Rate	4.4%						
Market Generation Cost							
Demand	69,101,487	88,112,079	132,920,818	140,210,763	152,735,985	166,270,096	171,441,096
Market Demand Rate [1]	2.774	3.537	5.336	5.628	6.131	6.674	6.882
Market Energy Rate [2]	0.028115	0.029988	0.030671	0.030956	0.032317	0.031148	0.033147
CTC Rates							
2. All KW	8.287	7.524	5.725	5.433	4.930	4.386	4.179
3. Kwh-First 150 Hrs	0.045547	0.043674	0.042991	0.042706	0.041345	0.042514	0.040515
4. Kwh-Next 150 Hrs	0.021363	0.019490	0.018806	0.018522	0.017160	0.018330	0.016330
5. Kwh-Addl Use	-0.002562	-0.004435	-0.005118	-0.005403	-0.006764	-0.005595	-0.007594
Estimated CTC Revenues	443,015,858	402,082,643	349,274,035	338,652,343	310,191,738	310,343,729	281,768,491
Less: GRT	-19,492,698	-17,691,636	-15,368,058	-14,900,703	-13,648,436	-13,655,124	-12,397,814
CTC Revenues w/o GRT	423,523,161	384,391,007	333,905,978	323,751,640	296,543,302	296,688,605	269,370,678

[1] Market Demand Cost unitized by adjusted sample billing determinants

[2] Weighted Average Market Energy price adjusted for losses and GRT

Exhibit ___ (SJB-8)

R00973953; R00973953C0001-C0007

PAIEUG STATEMENT NO. 1R

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	)	

REBUTTAL TESTIMONY

OF

STEPHEN J. BARON

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

JULY 1997

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	)	

TABLE OF CONTENTS

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT 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.

Q. What is the purpose of your rebuttal testimony?

A. I am responding to the direct testimony of the American Association of Retired Persons ("AARP"), the Office of Consumer Advocate ("OCA"), the Office of Trial

Staff ("OTS"), and the Environmentalists, among others, regarding proposals to assign the Universal Service Fund ("USF") costs to all customer classes on a volumetric, kWh energy basis. This is in contrast to PECO's proposal that assigns the USF revenue requirement to the residential class. The residential class is the customer class in which the recipients of the USF take electric service.

I will also briefly address proposals to assign stranded cost to rate classes on a kWh or other basis, in contrast to PECO's proposal to use a production demand allocator as identified in the legislation.

Finally, I will address an issue raised by Enron witness Michael D. Dirmeier concerning PECO competitive contract offerings under Tariff Rule 4.6 and issues raised by other parties concerning cost shifting within the unbundling process.

Universal Service Fund Recovery Mechanism Issues

Q. **Before specifically addressing the proposals made by the various parties (identified above) for a modification of PECO's proposed recovery mechanism for USF costs, would you please describe PECO's approach as outlined in its restructuring filing?**

A. PECO has assigned approximately $36 million of USF costs to the residential class and has proposed a tariff that would adjust the USF costs annually. PECO's rationale, as discussed in the testimony of witness Stephen R. Xander is that these USF costs are associated with residential customers on the PECO system and therefore should be assigned to this customer class.

Q. **Do you agree with PECO's proposed assignment of USF costs and its recovery mechanism?**

A. Yes. Since I agree with PECO's proposed methodology for recovering USF costs, I did not specifically address this issue in my direct testimony. In addition, since I adopted PECO's distribution cost allocation, I implicitly adopted the Company's USF assignments.

PECO's rationale for assigning USF costs directly to the residential class is reasonable and follows sound cost of service ratemaking principles. These costs are associated specifically with providing service to residential customers. The Competition Act specifically defines Universal Service as benefiting low-income customers. Therefore, it would be inappropriate to assign these costs to other customer classes. In addition, PECO has traditionally assigned these types of costs (uncollectible expenses) on a specific assignment basis. Thus, PECO's <u>current</u> bundled rates reflect the same cost allocation approach for "USF type costs" (predominately, uncollectible expenses) as is being proposed by the Company in this case for USF costs. To change this cost allocation method in this unbundling proceeding would violate cost shifting restrictions in the Act.

Q. Would you please summarize the basic positions of the various parties recommending an allocation of USF costs to customer classes on a non-bypassable, kWh basis?

A. In general, each of the witnesses for the various parties proposing an alternative USF allocation have recommended that these costs be assigned to customer classes on a per kWh basis through a non-bypassable surcharge.

Q. Based on your experience in Pennsylvania rate proceedings, has the Commission previously utilized an energy allocation factor to assign the types of costs included in the USF service fund?

A. No. Based on my experience in 25 rate proceedings in Pennsylvania since 1984, to the best of my knowledge, the PUC never has allocated "USF type costs" on the basis of class kWh energy. It would be egregious to assign these costs to other customer classes on a per kWh basis, as recommended by various parties in this proceeding.

Q. Why would it be inappropriate to use a kWh energy allocation factor to assign costs associated with providing low income assistance and uncollectible expenses?

A. From a cost of service basis, there can be no cost-causation relationship between the energy use of a particular customer and/or customer class and the incurrence of these costs by PECO. If, for example, a large industrial customer on the PECO system were to add an additional shift to its manufacturing operations and increase its kWh usage, there is no corresponding increase in the amount of low income assistance or uncollectible expense required for PECO's customers. In fact, just the opposite could be true since such manufacturing customers may actually increase employment in the PECO service area and reduce the need for assistance. Irrespective of this, there can be no cost-causation link between energy usage by a customer or a customer class and the level of USF costs. As such, it is totally violative of cost of service principles to assign these costs to rate classes on an energy basis. The proposals of the various parties to assign USF costs on a per kWh basis (through a separate charge) are therefore inconsistent with cost of service principles and, in my opinion inconsistent with the principles established in the Competition Act that rely on cost of service as a guide to rate unbundling. The rate cap on individual, unbundled components would be violated, as would the prohibition against inter- and intra-class cost-shifting, if a per kWh surcharge were imposed.

Q. **Some of the parties have suggested that the Competition Act itself requires that all customers pay for the USF charge through a non-bypassable ratemaking mechanism and that this implies all customers therefore should pay the same unit cost for USF costs. Do you agree with this interpretation?**

A. No. §2802(17) of the Competition Act states as follows:

> **"The public purpose is to be promoted by continuing universal** ***service and energy conservation polices, protections and services;*** **and full recovery of such costs is to be <u>permitted</u> through a non-bypassable rate mechanism."** (§2802(17), (emphasis added)

The language in the Act clearly indicates that recovery of USF costs is <u>permitted</u> through a non-bypassable rate mechanism. There is, however, no language that requires the Commission to assign these costs to all rate classes (nor is there any provision that requires the Commission to assign these costs to rate classes on a per kWh basis).

The various parties who are proposing a kWh assignment appear to be relying on this section of the Competition Act to justify assigning USF costs to all customer classes and doing so on a kWh basis. My interpretation of this portion of the Competition Act does not support any kWh energy assignment of USF costs to all customer classes.

Q. Are there any additional problems with the various proposals to assign USF costs to all customers and classes on the basis of kWh energy?

A. Yes. As a result of the component rate cap provisions of §2804(4)(i), customer cost responsibility for USF costs is capped at current levels. Therefore, proposals to assign USF costs on an energy basis would violate component rate caps. That is, to the extent that current customer rates do not reflect an assignment of USF costs to customer classes on an energy basis, doing so in the rate unbundling would violate the rate cap. Effectively, costs associated with USF programs, such as low income assistance and uncollectible expenses, are included in PECO's current bundled rates, and these costs are already reflected in the distribution and customer components of the rates and cannot be reassigned using an energy allocation factor in the rate unbundling process. In PECO's most recent base rate case in 1989, the Company assigned uncollectible expenses on a "specific assignment" basis, <u>not on an energy basis.</u> The proposals of various parties to assign USF costs on an energy basis is thus inconsistent with the most recently approved cost of service methodology. In addition, the effect of the proposals to assign USF costs on energy basis is to increase distribution revenue requirements for each rate schedule. PECO's distribution rates would exceed cost of service levels.

Q. Do you have any final comments regarding this issue?

A. The proposal of the various parties to assign USF costs on an energy basis to customer classes and to customers is a form of social ratemaking that should more properly be addressed by the legislature and not by the Commission through the imposition of an effective "tax" on energy usage. The bottom line effect of the proposals to assign USF costs on a per kWh basis is to impose an energy tax for the purpose of funding universal service, social welfare requirements. This is not to suggest that such funding, at reasonable levels, is inappropriate. However, the Commission should not establish rates to fund these programs through the mechanism of an energy usage tax, but rather, should follow traditional cost of service ratemaking principles in recovering these costs. There is no cost-causation relationship between USF costs and energy usage. The Commission should not impose such taxes on energy usage in Pennsylvania; rather, the legislature should address such issues. The Commission should follow cost-causation principles in establishing rates.

Finally, it is particularly inappropriate to consider the proposals by the various parties to assign USF costs on an energy basis in light of the desire of all parties to promote a viable retail competition market for generation resources. Imposing an energy tax on all kWh throughput, as discussed by one or more parties, would surely result in the diminishment of the relative competitiveness of Pennsylvania industry and other customers relative to other states where no such energy tax is imposed.

<u>Allocation of Stranded Costs</u>

Q. Do you have any comments on the proposals of the witnesses for the Environmentalists and the AARP to assign stranded cost to rate classes?

A. Yes. Environmentalists witness David Schoengold has proposed an allocation of CTC costs to rate classes on an energy basis (Environmentalists St. No. 2, p. 32). Although Mr. Schoengold admits that this would violate the Competition Act, he still believes that this is the most appropriate basis for assignment of these costs.

Mr. Schoengold is correct that his proposal would violate the provisions of the Competition Act. The stranded costs that would be recovered through a CTC are related to the deregulation of the generation component of the Company's rates. Generation-related costs that have been found by the Commission to be stranded are clearly related to production demand and should follow the production demand mechanism approved in the Company's most recent rate case. Mr. Schoengold's proposal to assign these costs on an energy basis is totally unreasonable and is not justified on any ratemaking or regulatory basis. Moreover, it would violate the prohibition against inter- and intra-class cost-shifting, in recovering stranded cost, as set forth in §2808(a) and §2812(g). Mr. Schoengold's proposal should be rejected without further consideration.

Q. Have you reviewed the testimony of AARP witness Dr. Mark N. Cooper regarding the assignment of stranded cost to rate classes?

A. Yes. Dr. Cooper also recommends, at page 32, lines 17 through 22 of his testimony that stranded cost associated with generation assets should be allocated on the basis of consumption (i.e., energy use). He then states that allocating stranded cost on the basis of consumption would tend to lighten the share to the residential class. Dr. Cooper's proposal violates the Competition Act with respect to the assignment of stranded cost to rate classes and, as discussed previously, would violate any reasonable ratemaking treatment of such costs, given that they are related to production facilities that have become stranded or will become stranded as a result of competition. Dr. Cooper's recommendation in this regard should be rejected.

<u>Other Issues</u>

Q. Are there any additional issues raised in the testimony of other parties in this proceeding that you wish to comment on?

A. Yes. Enron witness Michael D. Dirmeier has recommended in his direct testimony that PECO:

> **"should not be permitted to enter into market-priced contracts unless PECO first offers to competitive suppliers the opportunity to bid to provide service to the customer . . ."** (Enron St. No. 6, p. 12, lines 11-13).

The contracts that Mr. Dirmeier is referring to are currently permitted under Electric Tariff Rule 4.6 and the Economic Efficiency Rider ("EER"). PECO currently has a number of these contracts that have previously been submitted to the Pennsylvania Public Utility Commission. As Mr. Dirmeier points out in his testimony, PECO may also be negotiating with current customers for new contracts under these tariff provisions.

Q. Is there any reason why PECO should not be permitted to continue offering these contracts to its customers?

A. Absolutely not. PECO should be permitted to negotiate with its current customers for the purpose of establishing mutually agreeable contracts under Tariff Rule 4.6 or EER. Mr. Dirmeier's concerns do not reflect concerns of PECO's industrial customers, but rather a concern of alternative suppliers such as Enron that they may not be competitive in the interim period prior to full retail access. As noted by Mr. Dirmeier, however (in a footnote to his testimony), Enron and other alternative suppliers can negotiate contracts with such customers today for service beginning when retail access is permitted. They have complete rights to such negotiations. It is totally unreasonable to restrict the customer from discussions with PECO, or any other supplier, regarding future contracts.

Larger customers tend to be sophisticated with respect to the types of contracts that they are entering. It is unreasonable for Enron, as an alternative supplier, to request that the Commission issue a prohibition against such customers freely engaging in arms length negotiations with PECO to achieve contracts that are mutually agreeable to both parties. There is simply no basis for this position.

Q. Are there important competitive reasons to PECO's customers why PECO should be permitted to continue entering Rule 4.6 and EER contracts, if it is mutually agreeable between the Company and the customer?

A. Yes. The large industrial customers who are considering such contracts face competitive pressures today. Other industrial companies on the PECO system or other utility systems are currently purchasing electricity through negotiated, long-term contracts, similar to Rule 4.6 or EER contracts offered by PECO. If such customers are not permitted to consider all options, including entering a long-term contract with PECO today, they could be placed at a competitive disadvantage relative to other industrial firms in similar businesses on the PECO system, throughout Pennsylvania and throughout United States. Enron's proposal is not in the interest of Pennsylvania consumers and should be rejected.

Q. Do you have any additional comments on the testimony of other parties?

A. Yes. To the extent that any party proposes a change in cost allocation or the elimination of subsidies within the unbundling analysis, these proposals should be rejected since they would directly violate the cost-shifting and rate cap restrictions inherent in the Competition Act. For example, in the testimony of Municipal Intervenors Group's witness James Crist, he proposes that the Commission eliminate any existing subsidies paid by rate SL/E. This would clearly violate the cost-shifting restriction.

Q. Does that complete your rebuttal testimony?

A. Yes.

PAIEUG STATEMENT NO. 1SS

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

SUPPLEMENTAL SURREBUTTAL

TESTIMONY

OF

STEPHEN J. BARON

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

OCTOBER 1997

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

SUPPLEMENTAL 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 testimony in this proceeding?

A. Yes.

Q. What is the purpose of your supplemental surrebuttal testimony?

A. I am responding to the supplemental testimony submitted by witnesses on behalf of the Pennsylvania Electric Competition Coalition and the Mid-Atlantic Power Supply Association ("MAPSA"). With respect to the testimony submitted by the Pennsylvania Electric Competition Coalition, I am specifically responding to the testimony submitted by witnesses Steven A. Mitnick and B. Jeanine Hull.

In my testimony, I will address the proposed settlement from the perspective of one of the customer groups who participated in the settlement negotiations and became a signatory. The primary focus of the witnesses on behalf of the Pennsylvania Electric Competition Coalition and MAPSA (hereinafter referred to as "the Opposition Parties") has been on the impact of the settlement on PECO. In particular, the testimony of Steven Mitnick is primarily focused on the stranded cost recovery benefits achieved by PECO as a result of the settlement. My testimony, in response to the Opposition Parties testimony, discusses the settlement from the perspective of the customers who actually will be paying for the electricity provided by PECO or the alternative suppliers represented by the Pennsylvania Electric Competition Coalition and MAPSA. The interests of these customers, and the value conferred on these customers, should be the primary consideration of the Commission in evaluating the reasonableness of the proposed settlement.

Q. Do you believe that the proposed settlement is in the public interest?

A. Yes. Parties representing the vast majority of PECO's customers, including the Office of Consumer Advocate, the Office of Small Business Advocate and PAIEUG, representing large industrial customers, have unanimously endorsed the settlement. In addition, other parties, representing other consumer interests, have also agreed to the settlement. The fact that these customer groups, representing the vast majority of PECO's customers have agreed to the settlement is substantial evidence as to the justness and reasonableness of the settlement. To the best of my knowledge, negotiations took place on an arms-length basis among the various parties and between each party and PECO, and therefore represents a reasonable outcome with respect to the sharing of costs and benefits that would inure to each party, compared to the parties' litigation positions. Speaking for the members of PAIEUG, we believe that the settlement agreement confers substantial value on all customers, and, in particular, the PAIEUG membership. This is particularly significant in light of the fact that PAIEUG submitted substantial direct testimony in opposition to many aspects of PECO's filed restructuring case, including, but not limited to, PECO's market price assumptions and stranded cost quantifications.

Q. What issues did PAIEUG address in its direct testimony in this proceeding?

A. PAIEUG submitted the direct testimony of Randall Falkenberg on market prices and stranded generation costs and Lane Kollen on stranded regulatory assets. In addition, I testified on a number of policy issues related to the restructuring of PECO's rates in a competitive environment, including an alternative unbundling methodology. As a result of the significant analysis we undertook in the preparation of our direct testimony, we have developed a detailed understanding of PECO's stranded costs and other important aspects of this proceeding. This provided us with a strong foundation to critically evaluate the reasonableness of various settlement proposals provided to us by counsel during the negotiations.

Q. Based on your familiarity with the numerous issues being litigated in this proceeding concerning stranded cost, regulatory assets, rate unbundling and other implementation issues, do you believe the proposed settlement is reasonable?

A. Yes. Although the level of stranded cost that PECO may receive as a result of this settlement is greater than our litigation position, there are significant benefits that will inure to PECO's customers, including members of PAIEUG, which justify the approval of this settlement. In addition, the settlement confers benefits beyond those raised by

PAIEUG or other parties in their litigation positions that significantly assist PAIEUG members to respond and adjust to the many changes that will occur during the transition period. Among these "extra benefits" is a 10% rate reduction in the early years of the transition period, which begins four (4) months prior to the beginning of the retail access phase-in.

Another aspect of the settlement which is of significant value to PAIEUG members is the acceleration of the phase-in period for participation in retail competition. Under the Competition Act, only 33% of a customer class' load is entitled to participate in retail competition by January 1, 1999. Under the settlement agreement, up to 66% of the HT class peak load will have an opportunity to participate in retail access by January 2, 1999. By January 2, 2000, 100% of rate HT customer load can participate in direct access. This essentially accelerates the retail access phase-in by one full year compared to the legislation.

Another aspect of the settlement proposal that exceeds any parties' litigation position is a rate reduction occurring before January 1, 1999. Although this appears to be dismissed by the Opposition Parties, this is a substantial benefit to PECO's customers. It represents real cost savings to these customers as a result of the implementation of retail competition.

Q. Are there any other specific features of the settlement proposal that provide particular benefits to PAIEUG members?

A. Yes. The settlement agreement provides an assurance that PECO will continue to make available its current LILR, Rule 4.6 contract and EER contract tariff provisions though 2008. From the perspective of PAIEUG members, this is a substantial benefit that is being provided in the settlement agreement. Although PAIEUG members clearly look forward to the opportunities that will be made available as a result of retail competition and the provision of service by alternative suppliers, it is also beneficial to customers to know that their current rate schedules will continue to be available through 2008. While LILR remains frozen to existing customers, EER and Rule 4.6 will be available to current <u>and</u> prospective customers.

An additional feature that provides benefits to PAIEUG members, and all PECO customers, are the extensions of the T&D rate cap and the generation rate cap, beyond the period that would otherwise prevail under the Competition Act. The settlement also incorporates rates that reflect market prices that increase over time (the market generation component of the unbundled rate), following a pattern that is expected to occur in the marketplace, while incorporating a declining CTC factor each year. These two aspects of the proposed rate design, covering all customer rate schedules, provide benefits of certainty and predictability in large components of customers' bills as they transition into retail competition.

Finally, customers who self-generate or who were considering self-generation at the time the Competition Act passed can expand or pursue these efficient generation projects and share stranded cost responsibility with PECO.

Q. **Did the testimony of the Opposition Parties discuss these benefits to customers, based on your understanding?**

A. Not really. As I indicated, the focus of the Opposition Parties was primarily on the benefits of the settlement to PECO. Clearly, in any arms-length negotiation there are going to be benefits to both sides. In evaluating the reasonableness of the settlement agreement, however, it is important to recognize that both PECO and its customers received value as a result of the settlement and it is thus appropriate for the Commission to approve the agreement. Furthermore, the signatories to the settlement presented the most complete litigation positions on the issues now being challenged by the Opposition Parties -- stranded cost recovery level and market price. These signatories have concluded that the total package presented by the settlement sufficiently balances the interests of all parties and does not unduly compromise their respective litigation positions.

Q. One of the main issues addressed by the Opposition Parties is their belief that the embedded "market generation capped rates" that will result from this settlement agreement are too low and therefore, alternative generation suppliers will be foreclosed from participating in the market. Do you have any comments on this portion of the Opposition Parties' testimony?

A. To the best of my knowledge, none of the Opposition Parties submitted detailed market price studies in their direct testimony in this proceeding.[1] Despite the fact that these parties presented no substantial evidence on market prices in their main direct testimony in this proceeding, they are now asserting in their supplemental testimony that the market price component of PECO's unbundled rate will be insufficient to permit alternative suppliers to offer competitive rates, thus hampering the development of a competitive market. Unfortunately, without the presentation of detailed market price analyses by these parties in this proceeding, it is not possible to evaluate whether or not their assertions regarding the generation component of the settlement rates are in fact anti-competitive. At this point, their testimony is simply an unsupported assertion. The

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[1] Mr. Johnstone, on behalf of MAPSA, did provide a very simplified example of a market price estimate for 1999 in his testimony; however, this is not the type of analysis that would be necessary to support a stranded cost determination reflecting detailed market price calculations for 20 to 30 years into the future.

Commission should give strong weight to this fact in evaluating the reasonableness of their position in this case.

Q. Does that complete your testimony?

A. Yes it does.

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R-00973953, R00973953C0001-C0007

PAIEUG STATEMENT NO. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

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DIRECT TESTIMONY

AND EXHIBITS

OF

RANDALL J. FALKENBERG

DOCUMENT FOLDER

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

DOCKETED
NOV 04 1997

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

JUNE 1997

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

TABLE OF CONTENTS

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DIRECT 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.

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

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of J. Kennedy and Associates, Inc. ("Kennedy and Associates.")

Q. Please describe the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric, gas, and telephone utility industries. The firm provides expertise in system planning, load forecasting, financial analysis, cost of service, revenue requirements, and rate design.

I. QUALIFICATIONS

Q. Please describe your education and professional experience.

A. Falkenberg Exhibit ____(RJF-1) describes my education and experience within the utility industry. I have more than nineteen years of experience in the utility industry and have worked for utilities, both as an employee and as a consultant, and as a consultant to major corporations, state and federal government agencies, and public service commissions. I have been directly involved in a number of cases related to the Bath County, Beaver Valley, Brandon Shores, Grand Gulf, Limerick, Millstone, Palo Verde, Perry, River Bend, Susquehanna, Trimble County, Vogtle, and Wilson power plants concerning the topics of plant cancellation, phase-in, CWIP in the rate base, prudence, power system reliability, and economics.

During my employment with Ebasco Services in the late 1970s I developed probabilistic production cost and reliability models used in studies for twenty utility companies and the Wisconsin Public Service Commission Staff. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). At Ebasco, I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD III and PROSCREEN II planning models. In particular, I assisted planners in the application of these models to analyze revenue requirements and the financial impact of alternative expansion plans. I also assisted in EMA's educational seminars and trained utility personnel in revenue requirements analysis, production cost modeling, reliability analysis, and other techniques of generation planning.

Since joining Kennedy and Associates in 1984, I have been responsible for the firm's work in the areas of generation planning, reliability analysis, and the rate treatment of new capacity additions. I have presented expert testimony on these and other matters in more than seventy-five cases before regulatory commissions and courts in Arkansas, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, and West Virginia. Included in Exhibit ____(RJF-1) is a list of my appearances.

Q. **Have you previously appeared before the Pennsylvania Public Utility Commission ("PUC") or in proceedings involving utilities operating in both Pennsylvania and other jurisdictions?**

A. Yes. I have testified on about twenty previous occasions in cases involving the electric utilities operating in Pennsylvania and in other jurisdictions (Maryland, West Virginia and Ohio) in cases involving these companies' affiliate operations. In December 1995, I testified in the PUC's Electric Utility Restructuring Investigation (Docket No. I-940032) and most recently in PECO Energy Company's Application for Securitization (Docket No. R-00973877).

Q. Your testimony concerns marginal production costs and competitive market prices in Pennsylvania and the surrounding area. Please describe your relevant experience.

A. I have performed marginal analyses for nearly twenty years. As noted above, I authored production cost simulation models used by a large number of utilities for their initial PURPA filings in 1980. This model was used for many years by a number of Ebasco's clients.

Since 1982, I have been involved in a wide variety of consulting assignments related to power system modeling and analysis of the utilities in Pennsylvania and the surrounding states. From 1982 to 1984, I assisted a number of utilities in the region with implementation of the PROMOD III and PROSCREEN II planning models. I was involved in this work with training, modeling studies and database development for Duquesne Light, Allegheny Power System ("APS"), Atlantic Electric and Niagara Mohawk. After joining Kennedy and Associates in 1984, I became involved in the West Penn Power and Monongahela Power proceedings concerning Bath County. I also appeared in the Susquehanna II rate cases and testified regarding the economics of that project. In 1985, I testified concerning the economics of plant cancellation in the Limerick II investigation. In 1986 and 1989, I testified in the Philadelphia Electric Company ("PECO") Limerick I and Limerick II rate proceedings. Also in 1989, I testified in the West Penn Milesburg, et al. proceedings. In those projects, I modeled the economics or system reliability of each utility. More recently, I have testified in cases involving APS operating units in Maryland and West Virginia addressing the economics of proposed Qualifying Facilities' ("QF") contracts. By virtue of this work, I have examined studies, performed modeling, and conducted analysis of nearly all of the major Pennsylvania utilities at some time since 1982.

Q. A major focus of PECO's testimony in this proceeding concerns the modeling of a combination of the utilities in the region into a coordinated hourly spot energy market. Do you have experience related to modeling of production costs and/or market prices resulting from a combination of utilities?

A. Yes. In 1992, I was responsible for modeling of the production cost savings stemming from the Gulf States Utilities ("GSU")/Entergy merger. In that proceeding, I examined the fuel and production cost savings resulting from the joint dispatch of those two utilities. I testified concerning the results of my studies before the Louisiana Public Service Commission ("LPSC") and the FERC. My conclusion, that the savings estimated by the applicants were greatly overstated, was instrumental in the LPSC and FERC adoption of fuel cost "hold-harmless" provisions.

In addition, I have been involved in many projects over the past two years concerning the modeling of market prices in various regional power markets. Below I have listed my major activities:

1. Testimony regarding computer simulation of pool wide dispatch protocols, market price and market power in a hypothetical Pennsylvania power pool. (December 1995)

2. Publication in Public Utilities Fortnightly entitled PoolCo and Market Dominance related to the New York Power Pool (December 1995) and authorship of a companion article regarding Direct Access in New York. (February 1996).

3. Projection of market prices in PJM under both direct access and/or a power pool arrangement for (confidential) client due diligence analysis in evaluation of QF project. (February 1996)

4. Detailed Study of Impacts of Retail Access, Market Prices and Stranded Costs in a Ten State Southern Region for (confidential) state industrial intervention group. (March 1996)

5. Study of Electric Restructuring Issues for ERCOT: Market Prices, Market Power and Market Structure for the Office of Public Utility Counsel of Texas and presentation to Texas State Legislative aids. (November 1996)

6. Presentation of Direct Testimony and Exhibits related to market price forecasts and stranded costs estimates in the recent PECO Energy Company Securitization docket (Case No. R-00973877 or the Qualified Rate Order "QRO").

7. Participation as a panelist in the FERC Technical Conference related to Congestion Pricing in the PJM Restructuring Proceeding (Docket Nos OA97-261-000 and ER97-1082-000).

II. INTRODUCTION AND SUMMARY

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Philadelphia Area Industrial Energy Users Group ("PAIEUG"). This group includes many of the largest customers on the PECO Energy Company ("PECO" or "the Company") system. As such, they have a direct interest in the amount of stranded costs authorized for recovery from customers in this proceeding.

Q. What is the purpose of this testimony?

A. I will address issues related to the estimates of the market price for generation, and the resulting market value for PECO's generation resources. I will address the market price studies performed for PECO by ICF-Kaiser ("ICF"), EDS-Utilities Division ("EDS"), and Putnam, Hayes & Bartlett ("PHB"). This will concern the testimonies of Mr. Bustard, Dr. Hieronymus, and Dr. Venkateshwara. I will refer to these witnesses collectively as "the experts."

Q. Please summarize the conclusions and recommendations of your testimony.

A. My conclusions and recommendations are as follows:

1. **The PUC should use the same methods and market price forecasts to compute stranded costs for PECO, PP&L and GPU. PAIEUG agrees with PECO's basic methodology for computing stranded costs and recommends its application for all three Companies with certain important modifications to input data.**

2. **PAIEUG raised numerous issues in the QRO proceeding challenging the market energy and capacity prices projected by PECO. The Company has corrected for some of these criticisms in this case, particularly with respect to market energy prices in the PHB study. However, PECO now offsets the resulting increases in market energy prices with decreases in capacity prices and, the use of new, and even more optimistic, assumptions regarding the cost and performance of new generators. In the end, PECO seriously understates market prices for both capacity and energy.**

3. **Market price forecasts are dependent on heat rate data for generating units to produce market energy price forecasts. The PHB and EDS models do not rely on actual historical or tested heat rate data for individual generators. Rather, they estimate unit data using highly questionable and subjective methods. In the end, the PHB and EDS models systematically understate market energy prices because they use erroneous heat rates. All <u>three</u> studies rely on biased, erroneous, unrealistic or undocumented heat rate data.**

4. **Of the three studies filed by PECO, the PHB study is the <u>least</u> reliable indicator of market prices and stranded costs. The PHB study relies on the GE MAPS model which is unreliable for purposes of computing market energy prices.**

5. **All <u>three</u> of the studies filed by PECO understate market prices due to a variety of modeling infirmities and biased input assumptions. All <u>three</u> studies understate market prices by assuming that dual fuel units run only on natural gas and due to a number of less obvious and frequently inconsistent assumptions related to capacity prices.**

6. I present an independent modeling of market prices that corrects for the biases and errors in PECO's studies. Based on my assumptions and use of the Energy Information Administration 1997 fuel price forecast, I compute total generation related stranded costs for PECO of $1.88 billion. Use of these assumptions with the ICF fuel forecast results in a stranded cost of $1.3 billion. Using PHB's assumption and correcting <u>only</u> the most obvious errors in the PHB study, I compute a stranded cost of $2.5 billion under the DRI fuel forecast.

Q. Why should the Commission utilize a consistent stranded costs calculation methodology and market price assumptions in the PECO, PP&L and GPU restructuring cases?

A. PAIEUG believes that the PUC should utilize the same market prices and methodology to compute stranded costs in all three cases. All three utilities are in the PJM pool and absent locational differences, would face virtually the same market prices. The outcome of the PJM restructuring proceeding at the FERC will determine whether any significant locational price differences will even exist. However, both PP&L and PECO have produced substantial evidence that locational differences in market prices will not be substantial in PJM.[1] As a result, it would be unreasonable to assume these companies would face substantially different market prices.

1 See for example, the Testimony of PECO witnesses John Bustard (PECO Statement No. 4, pages 17-18), Dr. William Hieronymus (PECO statement No. 6, page 9 and Exhibit WHH-4, page 3) and PP&L witness Dr. Scott Jones (PP&L Docket No. R-00973954, Statement 7, pages 16-18).

PAIEUG further believes that the Commission should adopt the basic PECO methodology for computing market value as opposed to the PP&L approach. PECO's method is more of a market oriented approach and computes the loss to shareholders based on the shortfall between the after tax market value of their assets under competition compared to book value. The PP&L method attempts to compute the shareholder loss on the basis of the loss in pre-tax revenues under competition and regulation.

Q. Why do you prefer the PECO method of computing the shortfall in plant value rather than PP&L's approach which computes the loss of future revenues?

A. The PECO method is intended to compensate shareholders for the reduction in value of their property. The PP&L method, on the other hand, seeks to establish and protect a perceived right of shareholders to future revenue streams associated with a static form of regulation. Regulation has never preserved shareholder rights to future revenue. Regulation has only protected shareholders by providing an opportunity to earn a just and reasonable return on either the fair value or depreciated book value rate base. For this reason the PECO method is more appropriate for the purposes of this proceeding.

III. OVERVIEW AND SUMMARY OF THE QRO PROCEEDING

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

A. The PUC has, at least preliminarily, considered some of the issues in the case by virtue of PECO's recent QRO (or Securitization) proceeding. In this section of my testimony, I will briefly discuss a number of the issues in that case and contrast this restructuring case with the QRO case.

The QRO was the PUC's first substantial case dealing with one of the most crucial restructuring implementation issues: stranded asset securitization. PECO's decision to seek securitization <u>prior</u> to the restructuring case, combined with the compressed statutory procedural schedule, did not afford the usual amount of discovery and analysis by the parties. A securitization decision by the Commission is irreversible and the hasty adoption of understated market price forecasts could have forced ratepayers to overcompensate for PECO's stranded costs and, thereby, subsidize PECO's competitive future. For these reasons, PAIEUG recommended that the PUC not make any binding determination regarding market prices in the QRO case and, instead, employ a cautious and pragmatic evaluation of the justness and reasonableness of PECO's securitization request.

Q. Explain how this case differs.

A. In this case, the procedural schedule provides a better opportunity to examine the issues. In addition, this case examines the entire range of restructuring questions. While there will always be uncertainty regarding future projections, the time has come for the parties to make their <u>best estimate</u> of market prices and stranded costs applicable to all of PECO's assets, not just the portion that it sought to securitize in the QRO case. The time is now ripe for consideration of market price forecasts.

Q. Please summarize the main points you made in the securitization proceeding.

A. Based on my analysis of the evidence in that case I reached several key conclusions:

1. The PHB model added too much combined cycle generation to the PJM area given the input cost assumptions. This error caused an understatement of market energy prices.

2. The EDS model contained an error which resulted in understated capacity costs.

3. The ICF model used overly optimistic, and even biased, assumptions related to the cost and performance of new combined cycle generators as compared to other projections (including those of PHB and EDS), other independent sources and actual plants.

4. The discount rate used by PECO was based on the cost of capital from it last rate case and was too high relative to PECO's current cost of funds.

5. PECO's nuclear capacity factors for Peach Bottom and Limerick were far below recent experience.

6. Salem should be excluded from the calculation of stranded costs due to open questions related to its future operation.

7. I raised a number of other issues related to allocation of deferred income taxes, heat rate inputs in the models, and other factors.

Q. Have PECO's witnesses responded to your prior criticisms in the current filing?

A. Yes, they have, in part. PECO's witnesses did acknowledge in the prior case that problems existed in the PHB and EDS computer runs related to my first two points. PECO attempted to partially correct these problems in the rebuttal phase of the earlier case, but could not do so completely. I am now satisfied that PECO has, at least mathematically, corrected these errors with its filing in this case.[2] PECO also adopted an allocation of deferred income taxes for each market value study, rather than using an average figure for all three studies. In addition, PECO has used a lower discount rate based on a more recent cost of capital and PHB at least, increased its nuclear plant capacity factors. Overall these corrections have been significant. For example, in its initial QRO filing, PHB estimated a market value of PECO's generators of $2.038 billion. PHB's current estimate is $2.862 billion, an increase of $824 million, or more

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[2] This does not imply I now agree with the PHB and EDS studies. It simply means that the previously identified errors have been eliminated. There are still wide areas of disagreement regarding the assumptions related to these corrections.

than 40%. The EDS study filed in the prior proceeding estimated a market value of \$2.647 billion compared to its current estimate of \$3.650 billion, an increase of more than \$1 billion or 38%. Likewise, the ICF study increased market value from \$3.019 billion in the prior case to \$3.488 billion currently, an increase of nearly \$470 million or 15.5%.

Q. Does this mean you are satisfied with the results of PECO's new market price studies?

A. I appreciate PECO's willingness to accept valid criticisms and the fact that it has eliminated some of the issues and controversy from this proceeding. However, PECO's experts have not yet corrected all of the deficiencies in their respective studies. In some crucial areas they have apparently compensated for increases in market values stemming from the above corrections by changing other assumptions which were unrelated to my original criticisms. These changed input assumptions mask the true extent to which the previously identified errors understated PECO's forecasts of market prices.

Q. Could you provide an example of this?

A. Yes. The most obvious example relates to PECO's application of the three market studies. In the QRO proceeding PECO computed an average market value based on the three studies, yielding a result of $2.568 billion. In the current case it has simply adopted the lowest of the three studies, PHB's $2.862 billion estimate. While this is a rather obvious (and perhaps telling) difference, many significant, but far less obvious changes were made to input assumptions that further reduced PECO's estimates of market value. For example, Dr. Hieronymus *increased* the market energy prices in his MAPS simulation but substantially *decreased* his projected capacity prices. By substantially reducing the estimated cost of a combustion turbine, Dr. Hieronymus decreased market capacity prices by about $500 million relative to his earlier studies, while increasing the energy margins by roughly $1.3 billion. EDS made similar adjustments to its capacity cost estimates which had the further effect of offsetting the major error it corrected.

Q. Do you agree with the implications of PECO's selection of the lowest of its three forecasts for market value?

A. No. PECO has presented three independent forecasts of market prices. By selecting the lowest of the three it is implicitly suggesting that customers should bear the risk of forecast errors or uncertainty. Indeed, I will show in my testimony that PECO is assuming ratepayers should provide allowances for other risks, such as those related to possible technological progress that might benefit possible competitors. In effect, PECO is asking to not only be compensated for the possible losses resulting from a transition to competition but also, that the ratepayers assume some of the risks shareholders would ordinarily be expected to bear in a competitive environment.

Q. Did PECO address all of the issues you raised in the prior case?

A. No. I raised a number of issues related to the calculation of real fixed charge rates, heat rates, etc., that PECO simply did not address in either the prior or current filing.

Q. With that as a background please explain how you will proceed in the remainder of your testimony.

A. Rather than addressing each of PECO's three studies in separately I organize my discussion in three general topics: Market Energy Prices, Market Capacity Prices and problems with the PHB, EDS and ICF computer models. Finally, I will present my own independent modeling studies and my corrections to PECO's studies.

IV. CRITIQUE OF PECO MARKET ENERGY PRICES

Q. Before we start, please describe the steps you have taken to investigate the modeling of market prices performed by PECO's experts in this case.

A. I prepared discovery and reviewed the discovery of the parties to this case. Where I required clarification on data responses, I called PECO for explanations. I personally visited the offices of EDS, ICF and PHB, and reviewed their data inputs and discussed their modeling methods with Mr. Bustard and representatives of these firms. Also, by virtue of my participation in the PJM Restructuring proceeding at the Federal Energy Regulatory Commission ("FERC") I have been given the opportunity to discuss a range of topics related to PJM market prices with PECO staff members. In all of these discussions and discovery review sessions, PECO's representatives were quite candid and helpful.

Q. Please explain why you are discussing market energy prices and market capacity prices separately. Are the two independent?

A. No. Under competition suppliers will enter a market when the market prices are sufficient to recover both the capacity and energy cost of a new generator. Under perfect competition, market prices will equal the short run marginal cost of the least efficient resource required to meet the load plus any additional shortage (or rationing) costs that would be required to bring demands down to the level of available capacity. At present, none of the models presented by PECO actually compute shortage costs and the pool short run marginal energy costs in an integrated fashion. The implicit assumption made by the experts is that shortage costs will be sufficient over time to allow for recovery of the cost of new peaking capacity. As a result, the problem has largely been separated into an analysis of market energy prices and capacity prices. The EDS model recognizes the linkage between capacity and energy prices because it allows for the computation of market capacity prices that reflect the fuel cost savings a combined cycle unit may provide relative to a peaking plant. It can produce market capacity prices lower than that of a pure peaking plant. PHB and ICF also acknowledge that such a situation can occur. However, as a practical matter, neither found sufficient excess fuel savings for combined cycle units to reduce the cost of pure capacity below that of a new CT.

A. PJM Is The Relevant Regional Energy Market

Q. Explain the steps involved in estimation of market energy prices.

A. The first step is to determine the relevant regional energy market. In the case of the PHB and ICF studies it was decided that PJM, NYPP[3] and NEPOOL[4] were the relevant markets with some power imports allowed from ECAR[5], Hydro Quebec and Ontario Hydro. EDS modeled PJM, ECAR and SERC[6], but not NYPP or NEPOOL. Finally, Mr. Bustard prepared a market energy price forecast for 1999, which examined PJM and did not model specific loads or generators external to PJM. In the current PP&L restructuring case (Docket No. R-00973594), Dr. Scott Jones (PP&L's market price expert) also focussed on PJM alone.

Q. Do you agree with the market selections made by the PECO experts?

A. No. First, even PECO's own experts did not select the <u>same</u> regions for detailed modeling. In the case of EDS, for example, transactions with NYPP are probably far more important than possible transactions with Florida Power & Light (a SERC utility), or Consumers Power (an ECAR member). Even if one believed that such distant utilities might sell energy into the PJM market, it is worth noting that the progression

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3 New York Power Pool

4 New England Power Pool

5 East Central Area Reliability Coordination Agreement

6 Southeastern Electric Reliability Council

to competition has moved at a slower pace in SERC and ECAR than in PJM. Customers from utilities in those areas may not participate in competitive markets for some time, even assuming transmission costs did not render such transactions uneconomic. In the case of the ICF and PHB modeling, ECAR, particularly the area directly west of PJM (APS, Ohio Edison, and AEP) are more likely to be important suppliers in the PJM area than utilities in NEPOOL. In addition, transmission constraints exist between PJM and the other regions which limit the flows of power, and transmission charges between regions will tend to diminish the economic attractiveness of sources outside of PJM to retail consumers. Finally, the PROMOD IV study performed by Mr. Bustard reveals no significant reason to suspect it is necessary to perform a highly detailed simulation of loads and resources outside of PJM.

Q. **Can you provide any reasons <u>not</u> to expand the detailed simulation of loads and resources beyond PJM?**

A. Yes. I will demonstrate shortly that the EDS and PHB (GE MAPS) simulations really lack the prerequisite data to realistically model even PJM. Broadening the boundaries of the problem to include distant utilities requires even more data. I seriously doubt that adding more questionable data to an analysis can ever improve the validity of the results.

Q. What market area do you believe to be relevant?

A. I believe that the PJM area should be studied in detail with a specific modeling of loads and resources for each supplier. I believe it would also be reasonable to include forecasts of imports and exports of energy from other regions. However, I seriously doubt that anything of value is created by expanding the boundaries of the detailed analysis beyond PJM.

B. Critical Data Requirements Include Fuel Prices, Generator and Load Data

Q. What is the next step in the estimation of market energy prices?

A. The next step is to perform a production simulation of market energy prices. To do so, one must simulate the operation of a competitive bid-based (rather than regulated incremental cost-based) regional energy market. In short the model used must simulate a competitive market, not the heretofore regulated power pools.

Q. What kind of data is significant in this type of analysis?

A. Obviously, fuel prices are quite important, as is information about the regional mix of generation resources such as generator capacities, heat rates, availability statistics, and maintenance requirements. In addition, the demand side (customer energy demands, average energy and usage patterns) as well possible imports or exports of power from outside the region are important. Finally, assumptions related to capacity additions in the competitive market are also needed.

C. The PHB & EDS Studies Fail to Simulate Market-Based Bidding

Q. Do all of the PECO studies model a competitive bid-based market?

A. No. In fact, both the PHB and EDS studies (as well as Mr. Bustard's PROMOD study) represent a regulated incremental cost-based energy market and not a competitive bid-based market.

Q. This sounds important. Could you explain the difference?

A. Yes. Up until now utilities who have joined into centrally dispatched pools have developed procedures to share energy on the basis of a specific definition of *incremental* production costs. Within a tight pool such as PJM, market-based bidding was not allowed. Rather, units were dispatched based on split savings between unit incremental production costs. In a competitive market, utilities will be free to bid output to the pool at a price that may or may not equal incremental production costs, as currently defined by PJM pool rules. The transition to full retail competition will lead to a profound difference in the methods that utilities use to assess the attractiveness of making sales to the spot energy market, and this will lead to a fundamentally different bidding behavior by suppliers.

Q. Please explain.

A. Electricity is produced when a turbine-generator spins at a high enough rate to produce an electrical current. Spinning the massive turbine-generator requires a substantial amount of energy, even if no electricity is produced. The cost of this energy is called the no-load cost. Before the generator can produce any output, at least this amount of energy (and therefore cost) must be expended.

Under regulation PJM utilities dispatch generators on the basis of a pool wide cost minimization protocol. Units are committed and dispatched to serve load based on meeting reliability requirements, and minimizing total cost. Once a unit is already running for purposes of providing energy to the "obligation to serve" load, additional sales would be priced on the basis of recovering the *incremental* costs of increasing or decreasing a unit's output. In the example above, once a given unit is already up and running, incremental sales would be made if the value (to the buyer) of such energy exceeds the incremental cost (to the producer) of increasing the output of the marginal generator on the system. The obligation to serve customers would bear the no load costs of the unit because it was already running to serve their needs. This is the economic dispatch paradigm which has been practiced in the industry for many decades.

Q. **How does this differ from the bidding behavior you expect in a competitive market?**

A. Under competition the incremental cost-based system described above will be replaced by a bid-based system. The objective will be the maximization of producers' profits, not the minimization of pool energy costs. If it weren't for no-load costs, (assuming no market power) the two objectives would merge. However, no-load costs will force suppliers to change their bidding behavior from the current regulated incremental cost-based strategies. Under competition, there will be no "captive" customers to bear the no-load costs. Instead, the utility will find it must recover such costs within the framework of the bidding process. As such, they will increase bids above the current PJM definition of incremental cost by an amount sufficient to recover no load costs.

Thus, bidding will reflect the *average* heat rate of cycling generators, not the lower *incremental* costs of increasing the output of a generator that is already on line to serve captive loads.

Q. **A basic tenant of economic theory holds that in a competitive market, suppliers will set bids based on incremental cost. Are you suggesting this is wrong?**

A. Of course not. I am only suggesting that suppliers will change their definition of incremental costs to include all variable costs. You must realize that both the no-load costs and the conventionally defined incremental costs represent variable costs. Under the current regulated system recovery of no-load costs is assured. Thus, consideration of such costs is not a significant element of the existing bidding methodology. However, in a competitive market recovery of such costs will not automatically follow. Thus, the bid procedure will have to broaden the current definition of incremental costs to include all types of variable costs.

Q. **Could you provide a non-utility example which clarifies this point?**

A. Let's try an airline analogy. Assume you own a commercial airline and are considering starting service from Harrisburg to Washington, D.C. The cost of flying an empty jet on this route is substantial. This cost is clearly a variable cost and it would be incurred *before* any passengers are carried. The *incremental* cost of flying an additional 180 pound passenger is virtually unnoticeable compared to the cost of flying a 100-ton jet plane. Would you last long in the airline business if market prices were sufficient only to cover the incremental cost of carrying one additional passenger, while ignoring the cost of flying the empty plane and crew on your route? I doubt it. Instead, the reasonable business person would only fly such a route if the prices charged were sufficient to cover the average variable cost of the entire trip (the variable cost of flying the empty plane, crew, *and* the extra passenger.)

The current wholesale market functions quite differently from the above example. An appropriate analogy to the airline industry would be to consider the price a regulated package carrier monopoly might charge to add passenger service to existing routes. The regulator would like to encourage such activity, but is concerned about cross-subsidization between the two types of services. In this case, the plane is already flying for other reasons, and the package carrier conceivably could offer very low cost service. The regulator would probably insist that the freight carrier charge at least the cost for the extra fuel required to carry the added passengers. Assuming that conventional air service did not exist between Harrisburg and Washington, D.C., it is conceivable the regulator would also like to see the cost for the added passenger service to be as low as possible to promote overall economic efficiency. In the end, pricing the passenger service at the incremental cost of adding one passenger would make perfect sense. This is the appropriate analogy for the current regulated wholesale energy market. Note, however, that no airline could survive in a competitive market by offering such low prices.

Q. **Returning to electricity, please provide an example of this problem based on PECO's own units.**

A. Certainly. Figure 1 shows the average and incremental heat rates for PECO's Eddystone 4 unit as taken from the GE MAPS model used by Dr. Hieronymus. This figure shows that for Eddystone 4, the average heat rate as represented by the GE model is 11,410[7] btu/kWh at minimum load and 10,550 btu/kWh at full load. By contrast the assumed incremental heat rate is 10,270 btu/kWh. Under the current incremental cost-based system, PECO would be willing to make incremental sales out of Eddystone 4 so long as it is already running and it recovers fuel costs in excess of 10,270 btu/kWh. The additional costs of operating the unit (represented by the average heat rate curve) would be recovered from native load customers.

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[7] For clarity Figure 1 shows the heat rate divided by 1,000.

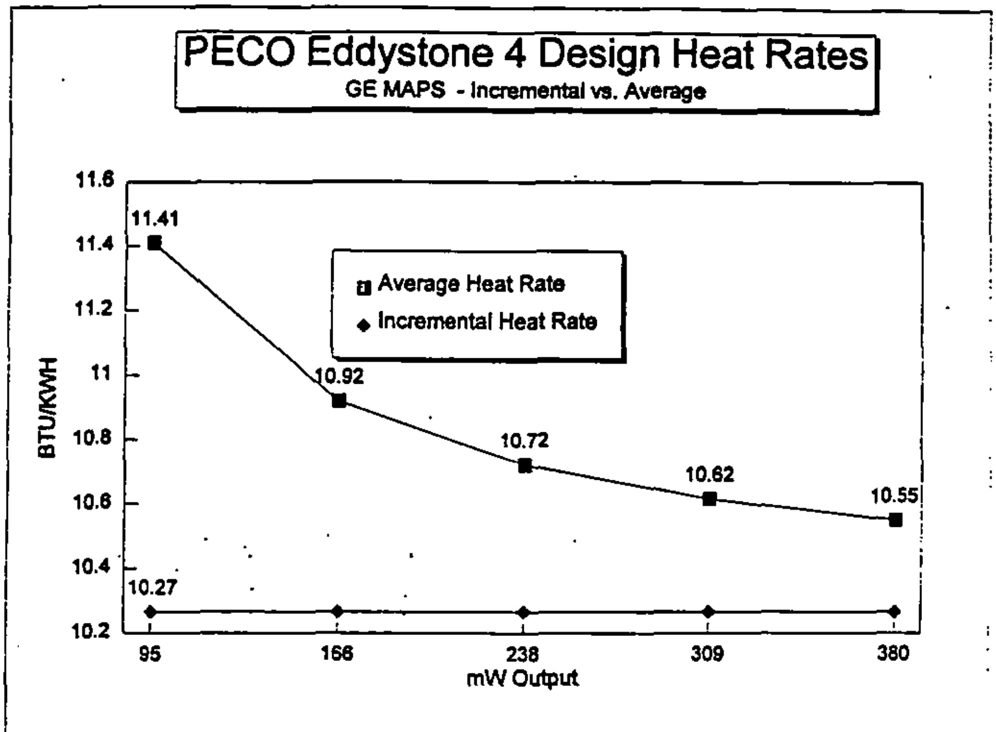

Figure 1

In a competitive market, PECO's objectives are now significantly different. PECO now seeks to maximize profits for shareholders rather than minimize prices to consumers. If Eddystone 4 is dispatched on the basis of a market clearing price sufficient only to recover the 10,270 btu/kWh, PECO will lose money! The reason is that PECO would have underbid its actual variable production cost. It would be far wiser for PECO to simply not run Eddystone when market prices are that low and, instead run the unit *only* when market prices are sufficient to recover all of the variable costs of running the unit. They would accomplish this by basing its bids for Eddystone 4 on the average rather than the incremental heat rate.

Depending on the actual loading of the unit, PECO's variable "cost" of production ranges between 11,410 btu/ kWh to 10,550 btu/kWh. The minimum PECO could ever afford to run Eddystone 4 would be at 10,550 btu/kWh, the full load average heat rate. Even this bid will be too low, if the unit is not dispatched at full load. Note that this reasoning even applies if Eddystone 4 is already running. If market prices in the next hour are expected to drop below the level sufficient to recover at least the cost of fuel at 10,550 btu/kWh, PECO would be wiser to shut down the unit for the rest of the day.

Q. Does this analysis you have just presented assume that PECO has market power?

A. No. It only assumes that PECO is *rational* and offers bids designed to maximize profits. PECO would not be exercising market power by *not* running its generators at a loss. Rather, it would be exercising sound business judgment.

Q. How representative is Figure 1 above compared to PECO's other generators as modeled in the GE MAPS program used by Dr. Hieronymus?

A. MAPS, as implemented by Dr. Hieronymus, represents every single unit as having a linear input output curve[8], with a single incremental heat rate at all loading segments. Every unit modeled will have a curve with a shape similar to the one shown above. In no case will the average heat rate at any loading fall below the incremental heat rate used in MAPS to simulate the bid-based dispatch. Given the simple heat rates represented in MAPS, it is impossible for a unit to operate at a profit when it is "on the margin." Dr. Hieronymus has systematically assumed that generators will bid at a price below their actual variable production cost and operate many hours during the year at prices below their average cost of fuel. The net result is to substantially drive down the market price of energy!

Q. Do other experts agree that bid prices in a competitive market will reflect average rather than incremental heat rates?

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[8] A linear input-output curve means that the output of a unit in mW's can be represented with a linear equation whose intercept is the no-load heat input and whose slope is the incremental heat rate.

A. Yes. In the PP&L Restructuring Case (PP&L Docket No. R-00973954), Dr. Scott Jones discussed this issue in response to an OCA data request (OCA Set III, Q45 part b). He stated that if the last unit is dispatched at a load level where its incremental heat rate is lower than its average heat rate, the incremental dispatch price will be lower than the total variable cost of that unit. He concluded that in a competitive market in which generators can bid their dispatch price, they will account for this factor in their bid for production of blocks of energy.

Q. Do any of PECO's experts also assume that bid prices will reflect average rather than incremental heat rates?

A. Yes. Dr. Venakateshwara's IPM model utilizes the EIA Form 860 heat rates which represent the most recent tested full load average heat rate for each unit. Dr. Venkateshwara has further stated in response to PAIEUG's data requests that in some case these average heat rates have been adjusted to represent expected operating conditions. Clearly, Dr. Venkateshwara and ICF recognize that it is proper to reflect the average heat rate of a unit in modeling a bid based competitive market:

> **"It should be noted that . . . [IPM] dispatches units based on a single heat rate value. The projected value represents the *average* efficiency of the unit during operation, which for some units will be well approximated by the full load heat rate."** (Emphasis added, Dr. B.S. Venkateshwara response to PAIEUG Data Request Set I, Q1.)

Q. **Aside from the fact that Dr. Venkateshwara's use of average heat rates supports your position, is there any other significance related to this fact?**

A. Absolutely. If ICF used the same fuel price assumptions as PHB and EDS (the DRI forecast) and held all other assumptions constant, the ICF model would produce higher market energy prices than do the PHB and EDS models. This would occur because DRI forecasts higher fuel prices than ICF.

Q. **Returning to the PHB and EDS studies, are there any telling signs that point to a problem related to the use of incremental heat rates?**

A. Yes. Dr. Hieronymus alludes to problems with "negative cycle days" where mid-cycle units that are priced on the basis of incremental heat rates may not run enough to recover starts up and no-load costs. The GE MAPS model is really a conventional production costing model designed under the premise of cost minimization in the current regulated wholesale power pooling arrangement. In models like MAPS, a unit may be called on to run a few hours, or at low loadings. As a result, it may have a high average heat rate. Under Dr. Hieronymus' assumptions, however, all sales are bid at the lower incremental cost. In these cases, the units in question operate at loss during hours when the system average heat rate falls above the unit's bid heat rate but below its average heat rate.

During a given day, when such losses outweigh profits in higher demand hours, Dr. Hieronymus calls it a "negative cycle day." Note that this concept has nothing to do with recovering fixed investment costs, or even fixed O&M expenses. In Dr. Hieronymus' implementation of MAPS, units run at times but fail to recover even variable fuel costs.

Q. How does Dr. Hieronymus account for the problems related to negative cycle days?

A. Dr. Hieronymus has hypothesized an "uplift" payment to compensate for these losses. However, his uplift payment only partially (and incorrectly) addresses this problem. While he implies that this is a minor problem, he has missed the great majority of the effect. Uplift payments to cure this "minor" problem produce significant additions to the market prices for the plants to which it is applied. For example, the uplift adjustment increases the market energy revenues of Eddystone 3 and 4 by 20% or more over the entire simulation period. Combustion Turbine ("CT") uplift payments are even more substantial, comprising more than 80% of total CT energy revenues.

Q. Provide an example from Dr. Hieronymus' exhibits that demonstrates the impact of the uplift payments.

A. I will return to Eddystone 3 and 4. In Dr. Hieronymus' 2004 simulation these units produce 1673 gWh and operate with a 25% capacity factor. The average cost of fuel for Eddystone is $36.6 $/mWh, while the market energy price (as paid during the hours that Eddystone is dispatched) is only $29.8. Under the PHB simulation PECO would be expected to expend $61 million in fuel costs and in order to recover $50 million in energy revenues in 2004. Under these circumstances, PECO would be better off if the unit simply did not run at all. In order to compensate for this shortfall Dr. Hieronymus assumes an uplift payment for Eddystone of approximately $11 million, the difference between the fuel cost and the market energy revenue.

Q. Does Dr. Hieronymus obtain similar results in his modeling of PECO's combustion turbines?

A. Yes. Exhibit No.___(WHH-4), page 6 shows that over the period 1999 to 2014, PECO's CT's are paid $54 million in total energy revenue, of which $44 million is uplift. Under Dr. Hieronymus' modeling of CT's, marginal costs are severely depressed during periods when CT's run. This happens because Dr. Hieronymus assumes that the minimum loading for a CT is 5% of full load. Under such circumstances CT bid prices are based on the (artificially understated) incremental heat rates while the average heat rates of these units at minimum loading are more than six times higher than the bid price. Review of Exhibit No.___(WHH-4), page 12 clearly reveals the problem. For example, in the year 2009 Dr. Hieronymus shows market energy prices for CT's of \$36.7/mWh, compared to an average fuel cost for the same units of \$437.7/mWh. Under this modeling it would seem impossible for a CT to ever run at a profit. In reality, PECO's CT's are seldom dispatched at less than full load, and even the PJM dispatch program that is now used to set unit loadings in real time considers both the *no load heat and incremental* heat rates of units in making the decision to start CT's.[9] As I discuss heat rates later in this testimony I will demonstrate how Dr. Hieronymus developed the erroneous heat rate assumptions which lead to these illogical results where CT's (and I believe nearly all mid-cycle units) run at a loss for many hours of the year. Figure 2, below shows the heat rate assumed by Dr. Hieronymus in the MAPS program for Croydon 42, one of PECO's most efficient combustion turbines. Note that at the 5% minimum loading, the average heat rate for the unit is more than <u>600%</u> of the incremental heat rate Dr. Hieronymus uses for setting bids from the unit.

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[9] In fact, if the PJM dispatch program actually used only the incremental heat rates to dispatch the CT's, PECO's Croydon units (which have very low incremental heat rates per PECO's response to PAIEUG I-2) would be running well ahead of many steam units in PJM.

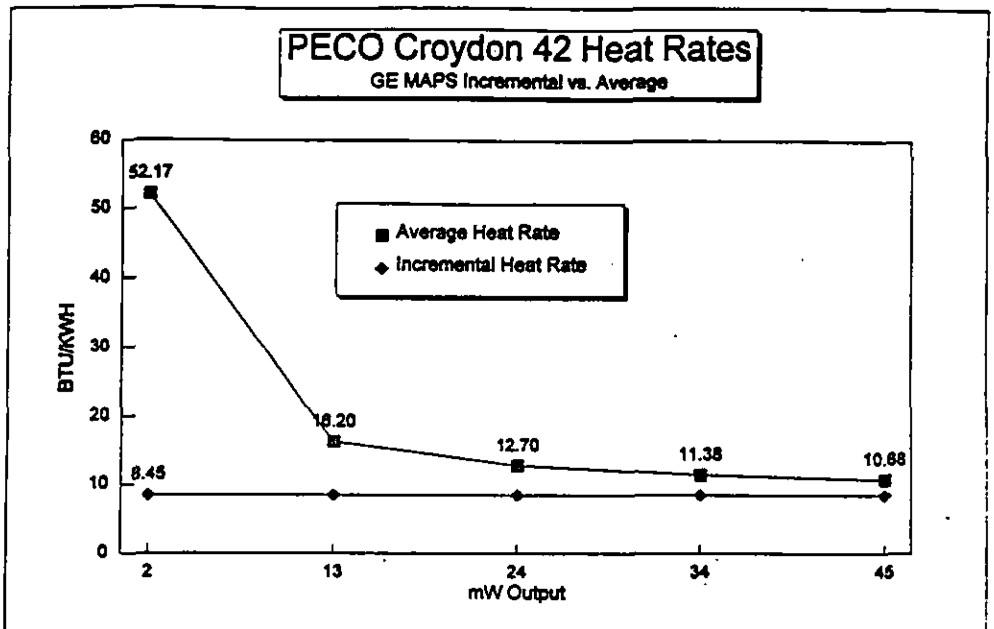

Figure 2

Q. What is the impact of assuming that shortfalls between incremental and average heat rates are made up via an uplift payment as opposed to the inclusion of no load costs in the bid prices?

A. There are two effects. First, the uplift payments only compensate the generators that have experienced a negative cycle day. A bid-based system using average heat rates would elevate market prices for all market participants, while the uplift system will only compensate the limited set of producers that are actually experiencing a negative cycle day. The practical impact of this modeling approach is that baseload plants would not see an increase in market prices because uplift payments would be made only to certain cycling plants. In effect, Dr. Hieronymus has assumed the existence of a system where generators are paid different marginal cost-based prices in the same hour. Profitable base load plants, and the more efficient cycling units, are paid on the basis of the *incremental* costs of the *unprofitable* cycling units at the margin. However, these same unprofitable cycling units are paid their own *average* variable production cost.

In any given hour, the last unit(s) dispatched will be operating at a loss. Thus, use of the incremental heat rates for bid prices systematically understates the marginal energy prices on the system. Because he recognizes that no rational producer will tolerate these circumstances, Dr. Hieronymus compensates unprofitable marginal units with uplift payments, while setting the prices for all other generators at the unprofitable price of the last unit, or units, dispatched. Returning to the example with Eddystone 3 and 4, Dr. Hieronymus has assumed that when these units are running the market price paid in PJM to the great majority of the generators would reflect the low incremental cost of energy from such units (less than $30/mWh in 2009). However, the Eddystone units would actually be paid their average production cost ($36.6/mWh in 2009). Thus, Dr. Hieronymus has hypothesized a two tiered market price and implicitly adopts the use of *average* heat rates for any unprofitable plants, while applying incremental heat rates (from these same unprofitable plants) to set prices for lower cost units.[10]

In the end, Dr. Hieronymus has not assumed a true competitive market. Rather, he has assumed a regulatory overlay to "fix" his problem stemming from the erroneous and understated bid prices.

Q. What is the second problem with the uplift payment scheme?

A. The second problem with the uplift approach hypothesized by Dr. Hieronymus is that it would replace the profit maximization objective with a "break-even" objective. During a negative cycle day a generator would only be compensated for losses to the extent that they exceed profits. Even with an uplift payment such a cycling generator would at best break even.[11] While the uplift payment would compensate generators for negative cycle days, it would give them no incentive to actually operate on such day. At best, they would be indifferent as to whether they would operate at all or simply shut

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[10] I doubt that Dr. Hieronymus has taken a serious look at the implications of this problem on a pool wide basis. For example, while he postulates the existence of uplift payments, he has never identified the source of revenues to make these payments. Considering that PECO has few cycling units, this would not be a major amount of money for its units. However, PECO's share of the total pool uplift payments could be substantial.

[11] This would be a reasonable assumption if the PJM utilities were satisfied with being non-profit organizations as opposed to profit maximizers.

down. In fact, it would provide incentives to place possible negative cycle units on outage because the reduction in pool supply would tend to increase prices. However, by bidding at a price above their incremental heat rate (say at the average full load heat rate) generators could limit their actual number of hours of operation to include only those hours when they would break even or make a profit. Instead of operating for 10 hours and only breaking even with uplift payments, generators could actually run for 4 hours, for example, and make a profit, by bidding at their actual average cost of energy.

Another problem with the PHB uplift approach is that in many cases generators could turn a profit during a cycle, but operate at a loss for some of the hours. In such case the uplift payment does not compensate the producer for lost profits. Once again, an astute producer would simply increase bid prices to cover the higher average heat rate and not operate during any hours where it might lose money. Assuming that the unit is fully loaded and perfect competition exists, the profit maximizing bid would be the average heat rate at full load. This is the opposite of the situation Dr. Hieronymus modeled for CT's. He assumed CT's would run at very low loadings (resulting in extremely high average costs) and bid (artificially understated) incremental costs.

Q. **Dr. Hieronymus testifies that it is his understanding of the PJM restructuring proceeding at the FERC that the Supporting Companies have been directed to**

develop an uplift payment mechanism. Does this invalidate your earlier comments?

A. No. The FERC has accepted the PJM Supporting Companies restructuring proposal with the notable exception of congestion pricing. However, the current PJM pool bid protocol is temporarily limited to bids based on incremental cost. The Supporting Companies' December 31, 1996 compliance filing makes it clear that this constraint is intended to be a temporary limitation which is only in effect until such time as various issues can be resolved and the FERC can be assured that market power does not exist:

> **"At the same time, on an interim basis both PECO and the Supporting Companies propose to retain many aspects of the interchange energy market"**
>
> * * *
>
> **"Finally, both PECO and the Supporting Companies would require that the bids for all generating resources in the PJM control area be based on the incremental operating costs of the generating resource, determined in accordance with the current PJM rules."**
>
> * * *
>
> **"The Supporting Companies are proposing the cost-based cap on bids of control area generation into interchange as a means of mitigating any potential market power concerns that might otherwise be present, while the stakeholders continue to discuss more comprehensive pool restructuring proposals and while the Supporting Companies consider the guidance provided in the Commissions's recent order in Docket No. ER96-1663-000 concerning the showing that must be made to support unconstrained market-based pricing a regional spot energy market. The Supporting Companies reserve the right (either individually or collectively) to propose the elimination of the cost-based bidding requirement by demonstrating**

> **that they lack or have mitigated any market power in the PJM energy interchange market.** ***Nothing in this filing is intended to relinquish any market-based pricing authority any of the companies already has to enter into bilateral transactions.*"** (Emphasis added, December 31, 1996 Brief of The Supporting Companies, Compliance Filing Docket No. OA97-000, pages 28-31.)

The necessity for an uplift mechanism under the above referenced temporarily constrained cost-based bidding system is not in dispute. However, once the restraint is eliminated, it will make no sense to have an uplift payment scheme because generators will (as demonstrated above) see that bidding at incremental cost (and receiving an uplift payment) assures *at best* they will break even, while bidding at average cost will *at worst* break even and probably make a profit. Even if the uplift scheme stays in effect, once market based bidding is allowed, it is unlikely any generators will actually avail themselves of this mechanism, for the reasons previously discussed.[12]

In addition, it is worth noting that PECO's PJM restructuring proposal assumed no load costs would be rolled into bid prices. I believe it is rather inconsistent for PECO to assume an uplift payment for this proceeding when it did not support this mechanism at the FERC.

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12 In addition, it would seem ridiculous to provide uplift payments to generators simply because they *chose* to bid too low. This would undermine any rational bidding system.

Q. Are there any other reasons why the uplift mechanism would be inconsistent with an unconstrained competitive bid system?

A. Yes. This artificial delineation of the market into two pricing tiers would inevitably lead to price gaming. Once a generator realized that the average cost of energy in the pool was below its incremental production cost (but not sufficiently so to result in a negative cycle day) and that certain generators were being paid uplift, they would logically raise their bids to the average cost of the marginal plant (incremental fuel plus uplift). This would not alter the dispatch sequence, but would ensure that generators increase their profitability. In the end, the de-facto bid price would become the average cost of energy of the marginal plant.

Finally, even assuming that *both* the restraint to bid at incremental cost and the uplift system stayed in effect indefinitely, producers would seek other means of increasing profits. If the current constrained system were to be perpetuated indefinitely, it would make the spot energy pool a rather unattractive market. Producers would naturally find a far greater incentive to enter into bilateral transactions where bid prices could fully recover production costs. As noted above, nothing in the Supporting Companies' current restructuring proposal at the FERC is intended to preclude the use of bids in excess of the incremental cost of generation in bilateral transactions. A utility's choice would be to bid cycling generation into the pool and, at best, break even, or sell it in a bilateral and make a profit. In the end, Dr. Hieronymus may have inadvertently demonstrated a good argument for perpetually limiting the PJM pool to bids based on incremental production costs: it would be a great stimulus for development of the bilateral market.

Q. **According to Dr. Hieronymus, the total uplift payments for PECO amount to only $.3 to $.5/mWh. Is this really as significant of a problem as you contend?**

A. Because PECO has only a few mid-cycle plants, Dr. Hieronymus has greatly understated the significance of this problem. As noted above, the real impact is on the elevation of average market energy prices as opposed to the minor increases in revenues for PECO's few cycling plants. Dr. Hieronymus has totally failed to include the impacts of this problem on market prices. The level of the adjustment required for Eddystone 3 and 4 clearly demonstrates the significance of this problem, yet Dr. Hieronymus makes only a partial adjustment to a few of PECO's plants to account for this problem. To see why this is so significant recognize that none of PECO's cycling units (either Eddystone 3 and 4, or the CT's) make a profit during any simulation year without the uplift payments.[13]

Q. Did Dr. Hieronymus even consider alternatives to the use of an uplift mechanism?

A. No. Based on his response to OCA V-11, Dr. Hieronymus did not perform any investigation of alternatives to his assumed uplift mechanism. This is interesting because the uplift mechanism was not used by PECO's other experts or by PP&L's witness, Dr. Jones.

Q. Do similar comments apply in the case of the EDS model?

A. Yes. The EDS model has the same problem related to incremental vs. average heat rates but does not even provide an uplift payment for compensation. Based on my discussions with the EDS consultants (in the QRO proceeding), it is my understanding that PMDAM does not dispatch units during negative cycles and instead would wait until periods when marginal costs are sufficient to cover the average cycle costs. A

[13] This raises a related problem in that Dr. Hieronymus shows that several of PECO's oil fired cycling units retire in 1999. I suspect he retired Delaware, Cromby and Schuylkill units because at best they break even on an energy basis (after uplift) and have no margin available to offset fixed O&M or other costs. If Dr. Hieronymus were consistent at all he would at least examine the implications of this problem for other PJM generators and I suspect, retire a great majority of the older cycling plants. This would in turn further increase market energy prices.

basic problem with this is that the EDS model would still allow profitable operational periods to offset losses during unprofitable periods. Thus, the EDS model suffers from most of the same problems as is the case with the PHB (GE MAPS) model. In both cases, the models are simply improper tools for the problem at hand.

Q. You raised some of these points in your QRO testimony. Did any of the PECO witnesses respond to this in rebuttal?

A. Dr. Hieronymus testified in his rebuttal testimony in the QRO proceeding that the uplift mechanism was proposed by the PJM supporting companies. He also stated that an extensive discussion of why it would be incorrect to dispatch all units at their average heat rates to avoid the negative cycle problem was inappropriate for that proceeding. I agree that the QRO was a compressed proceeding, but believe the time is now ripe for Dr. Hieronymus to respond to this issue.

Q. Are there any circumstances when it would make sense to bid at a price below the cost based on an average heat rate?

A. In some cases it might make sense to bid units with long minimum down times at a lower price. The reason is that if such a unit is shut down it may take too long to restart in order to be available the next day. Thus, units which cannot cycle may find it necessary to offer bids below average cost. However, there are a number of factors which indicate that this is a minor issue from a modeling perspective. First, even units which cannot be shut down overnight can frequently be shut down over a weekend. Thus, the choice to run a unit during a given week should center around the ability to recover at least the average fuel costs in the cycle. Second, the timing of the unit's weekly startup and shutdown should also be driven by consideration of recovery of average fuel costs. Third, during most hours margins are not set by such units. Finally, incremental heat rates (at least as used in MAPS) for such units average 96-98% of the full load average heat rate. Thus, there is little difference between incremental and average heat rates in such cases to begin with.

D. PECO's Input Heat Rate Data is Biased, Inconsistent, and Poorly Documented

Q. **Putting aside the questions related to use of the average vs. incremental heat rates, are you satisfied with the quality of the heat rate data used in the PECO studies?**

A. No. Neither PHB, nor EDS actually had incremental heat rate data to start with. In both cases the consultants went to great lengths to "manufacture" the erroneous *incremental* heat rates from *average* heat rate data. I consider the original ICF source inputs (the actual tested full load *average* heat rates as reported in the EIA Form 860) to be more reasonable.

Q. **Please explain how the incremental heat rates were manufactured in the PHB and EDS studies.**

A. This is explained in Exhibit Nos.____(RJF-2) and (RJF-3). These are PECO's responses to my data requests where I asked for an explanation of the process used. I will briefly summarize each method.

In the case of the PHB study, the starting point is the GE (not PHB) estimate of the *full load average design heat rate* for individual generators. Note that these design heat rates apparently make little or no distinctions for ages of units, changes in fuels, additions of scrubbers, etc. Degradation in unit efficiencies over time, for example, or fuel switching from oil to gas apparently do not impact the GE design heat rate. The actual source of the design heat rate from GE is still unclear. At best they represent the *engineering judgment* of the expected efficiency of typical generators of various types.

After the design heat rate is determined, a "rule" is applied to derive the average heat rate at minimum (required in the GE model to compute average fuel costs). For peaking units this rule amounts to assuming that average minimum load heat rates (at 5% of the full load capacity) is five times the average full load heat rate. For coal fired plants the rule is that at minimum load (25% of full capacity) the average heat rate is 12% higher than the average heat rate at full load.

The same "rules" are applied to derive incremental heat rates. For peaking units the incremental heat rate is about 78% of the full load heat rates. For coal fired plants the rule is that the incremental heat rate is about 96% of the full load heat rate. For combined cycle units the rule implies that the average heat rate at minimum is 25% higher than the full load average, while the incremental heat rate is about 94% of the average full load heat rate. In the end, this approach has a far more significant impact on the heat rates for cycling and peaking units than is the case for baseload coal plants. GE used this process to estimate all of the heat rate data for all PJM, NYPP and NEPOOL generators.

Q. **What is the basis for the actual figures used in the process described above?**

A. Dr. Hieronymus stated in response to PAIEUG VI-7 as follows: "*These data represent GE's engineering assessment and there are no supporting documents to back up these* *assumptions.*" I believe that this demonstrates a total lack of credibility in the PHB study. Even the most basic input data has no underlying support.

Q. Did PHB make any further adjustments to GE's *manufactured* incremental design heat rates?

A. Yes. Dr. Hieronymus made another adjustment for apparent discrepancies between the actual operational heat rates of units and the design heat rates in the GE MAPS database. He made another 5% to 10% adjustment to certain plants to increase the heat rates in cases where the GE design figures appeared too low compared to actual experience. However, even these adjustments seem to have little relationship to the calculated disparities between the design heat rate figures and actual results as can be seen by reviewing his responses to the OCA's data request in the QRO proceeding (OCA-II-19).

Q. How well do the GE design heat rates track the actual values for PECO units?

A. The GE design heat rates systematically understate the actual heat rates for PECO's units. In PECO's confidential response to PAIEUG Data Request I-2, I obtained the *actual* heat rates used in the PJM dispatch program. I compared these heat rates to those used in MAPS (which were provided in the QRO in PECO's response to PAIEUG Data

Request I-1(k)). For 44 fossil units provided, the MAPS heat rates under-predicted 36 units. These under-predictions were as large as 18% in some case. The MAPS heat rates only over-predicted eight units, and of those no over prediction exceeded 3%. On average the MAPS heat rates values were only 96% of actual, even after the 5% and 10% adjustments made by Dr. Hieronymus to the GE design heat rates. I believe that it is safe to assume the GE heat rates fared no better for the other PJM units and that we can reasonably assume that the 5% and 10% corrections were applied less frequently for other PJM utilities than for PECO. Clearly, the average full load heat rates used by GE were understated even before (and after) they were *adjusted* and then *remanufactured* as incremental heat rates for use in the PHB/GE MAPS model. While a 4% understatement of heat rates may not seem large, the PUC should recognize that it amounts to more than $30 million in additional market revenue in 1999 alone.

Q. **Please discuss the EDS methodology for producing incremental heat rates.**

A. EDS started with even less data than GE and tried to take it even further. The EDS model segments units into a number of heat rate blocks. To do so it requires an average heat rate at minimum and multiple incremental heat rates. The starting point of the EDS analysis was not a unit specific design heat rate, or tested heat rate. Rather, it was the *station* average heat rate as reported in the FERC Form 1. To derive the multiple heat rates for each unit (four per unit are required), EDS ratios the average station heat rates with figures reported for various types of generators as reported in a 1980's vintage EPRI Technology Assessment Guide. For a plant like Eddystone with two gas/oil and two coal units, the EDS approach would manufacture 16 heat rates from one Form 1 result for the Eddystone station. The best that can be said about the EDS modeling of heat rates in general is that EDS *tried* to develop the needed heat rate curve inputs. It should be rather obvious that the EDS heat rate estimation procedure uses very little actual data. Because different units at a station frequently have different duty cycles, vintages, sizes and even fuel types, I seriously doubt the EDS procedure is any better than simply using the average annual heat rate data listed in the Form 1 in the first place.

In fact, comparison of the EDS manufactured heat rates to a sample of PECO's actual unit heat rate data reveals some serious problems. First, the EDS heat rates were poor predictors of the actual heat rates for the sample units. The EDS *full load average* heat rates had an average absolute error of 5.3% compared to 2.8% for the EIA heat rates, a difference of about 90%. The EDS *incremental* heat rates had absolute errors as high as 14.5%, and averaged a 7.7% absolute error. Excluding CT's (because they are seldom dispatched at less than full load) the EIA full load *average* heat rates had an average absolute error about the same as the EDS incremental heat rates. Thus, there is little reason to expect the process used by EDS is any better than using the EIA full load average heat rate for predicting incremental heat rates for individual units, even if one accepted that goal.

However, my review of the EDS heat rates reveals systematic problems. On average the EDS heat rates *overstate* the full load average heat rate and *understate* the incremental heat rates. It is the spread between unit average and system incremental heat rates that determines the profitability of a given plant. I found that the EDS heat rates understate this spread by 4.7%. In other words, the EDS heat rates overstate the average cost of fuel for individual units, while understating the market energy prices. The EDS heat rates are systematically biased and understate profit margins.

Given my earlier comments regarding the inappropriateness of incremental heat rates in general the entire process is not only unnecessary but also wrong. This is clearly a case of trying to extract more (wrong) information from a data set than it really contains.

Q. **Based on this discussion it appears that you prefer the EIA Form 860 heat rates relied upon by ICF. Is that correct?**

A. Yes. ICF relies on the Form 860 full load average heat rates. It makes far more sense to use this type of publicly available average heat rate data, than to attempt to manufacture (unnecessary and erroneous) incremental heat rates from average design heat rates or reported station average heat rates. However, I do have a few concerns about the ICF data. ICF does not rely solely on the EIA Form 860 data. According to ICF's response to PAIEUG I-1, it attempts to "improve" this data by unspecified and undocumented consideration of *"plant specific data, engineering data and ICF judgment regarding heat rate degradation and improvements."* Based on ICF's response to PAIEUG II-9 and II-11, ICF maintains no database or records of *any kind* which documents the ultimate sources of data used in the IPM data base:

> **". . . ICF does not maintain a formal data base containing the records for the source of every input assumption to the IPM. In most cases, these sources can be traced to the data sources discussed in PAIEUG-II-6-7-8. In other cases these sources are tracked on an informal basis and pin-pointing the data source is labor intensive."** (ICF Response to PAIEUG II-11).

Q. Is this a significant concern?

Yes. When I visited ICF's offices to review the IPM data, the PECO and ICF representatives were generally well organized and prepared to answer nearly all of my questions. However, on this very important topic I did not receive very explicit information. I later inquired about this heat rate adjustment process and requested a demonstration of how the adjustments were made for specific units. As yet, I have not been provided with a satisfactory response. Instead, all that was provided was a table showing a comparison of Form 860 heat rates and heat rates for a sample of units. ICF may have valid reasons for adjusting the Form 860 heat rates. However, there is little reason to have any confidence in ICF's heat rates, that differ from those in the Form 860 at this time.

Q. **I believe that you have fairly well exhausted the heat rate issue for existing units. Do you have concerns regarding the heat rates for new generators?**

A. Yes. In my QRO testimony I pointed out that ICF consistently had used the most optimistic assumptions regarding the cost and performance of new combined cycle plants. Interestingly enough, I did not find any of the sorts of glaring mistakes in the ICF study[14] presented in the QRO as I did with the EDS and PHB studies. Now EDS and PHB have "corrected" the previously identified errors, and "updated" other assumptions. Examination of the changes to the heat rates for new combined cycle

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[14] I did conclude that the ICF study was seriously biased. However a bias is not the same thing as a error, such as were found in the PHB and EDS studies.

plants is telling, for it raises the concern that the input data selection process was result oriented.

Q. Please elaborate.

A. The table below summarizes the assumptions relative to the heat rates for new combined cycle plants in the QRO vs. those now being made by PECO's experts:

	Comparison of New Combined Cycle Plant Full Load Heat Rates (btu/kWh)		
Case:	ICF	EDS	PHB
QRO	6700	7483	7000
Current	6700	6386	6600

EDS went from having the most pessimistic[15] assumptions regarding combined cycle plant heat rates to being the most optimistic and is projecting an efficiency improvement of more than 1,000 btu/kWh, or almost 15%. PHB also projected a substantial gain in efficiency.[16]

15 And the most realistic compared to existing plants.

16 In fairness to PHB I would point out that the combined cycle heat rate is of limited impact because they assume only CT's would be built in PJM. However, they do assume some combined cycle

Q. **Are these forecasts optimistic compared to currently operating plants?**

A. Yes. I have researched a number of recently completed projects (PSE&G's Bergen plant, Delmarva's Hay Road plant, and two built by Florida Power & Light.). None of these plants exhibit the low heat rates shown above. In 1995 Bergen operated with a heat rate of 8,089 (and I estimate a full load heat rate of 8,080 from the EIA Form 860). The Delmarva plant operated in 1995 with a 7,782 btu/kWh heat rate and approximately a 50% capacity factor, while the FP&L plants (which were base loaded) showed an average heat rate of 7,390 btu/kWh. The FP&L and PSE&G plants are re-powering projects, an approach which I expect to be appealing to existing utility suppliers with a large fleet of older power plants.

I also recently toured a combined cycle cogeneration project in Florida. I learned that the heat rate for that facility (a state of the art unit built in 1994, and the most efficient power plant in Florida) achieved a full load heat rate under the best conditions 7,200 btu/kWh. Clearly, PECO's experts are projecting substantial improvements in combined cycle plant efficiencies. In effect they are asking ratepayers to provide an

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plants would be built in other regions. The EDS and ICF models add mostly combined cycle generation over the forecast horizon.

additional stranded cost allowance to protect the Company against possible improvements in the efficiency of potential competitors.

Q. Do you have any final comments regarding this subject?

A. The Commission must be extremely skeptical that such dramatic changes to heat rate inputs were caused by an "update" to input data assumptions, particularly in the case of the EDS study. According the Mr. Bustard's testimony in the QRO proceeding, the EDS model was already used by EDS to provide market price projections for 15 utility clients in the US. How EDS could have been so far off in some of these critical assumptions after having performed such projections for a large number of clients is surprising to me as an analyst. Such substantial downward revisions to key input assumptions under the guise of an "update" cannot inspire confidence in the Commission's use of this data which so directly impacts market prices and stranded costs.

E. PECO's Fuel Price Assumptions are Unrealistic and Overstate Stranded Costs

Q. Another item you mentioned in your list of critical input factors was fuel prices. Do you agree with the experts' fuel price assumptions?

A. No. Based on my review of the input data assumptions used in each of the three studies I have found that the experts have systematically understated fuel cost for PJM generators. For example, I discovered that in cases where units could run on either gas or oil, PHB, EDS and ICF uniformly[17] assumed that gas fuel would be used exclusively. This is unrealistic for a variety of reasons. Historically, dual fuel units have burned a mix of gas and oil. Nearly all of the gas consumed in PJM is interruptible. In the winter heating season gas deliveries are frequently curtailed. In these cases many units switch from gas to oil. In addition, many steam units have higher heat rates and lower capacity ratings when fueled with natural gas than with oil.[18] Thus the use of gas fuel in power plants should also be accompanied by an increase in heat rates and in some cases a reduction in capacity. I do not believe that the experts made any such adjustments to their data bases to recognize the impact of this problem.

In the case of the EDS study an even more extreme fuel assumption was made. EDS assumed that all residual oil unit prices were equal to natural gas. This can be seen by examination of Exhibit JFB-8 by comparing the prices for Delaware residual oil with

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17 This is true except for a few units in the PHB modeling.

18 This is supported by PECO's confidential response to PAIEUG I-2. An example is seen by comparing the gas and oil heat rates for Eddystone 3 and 4.

Cromby natural gas. Mr. Bustard has further confirmed that this assumption was made for all residual fuel units.[18]

Another problem common to all three studies relates to the use of distillate fuel in peaking units. A number of peaking plants in PJM are listed in the OE-411 as being fueled with kerosene (jet fuel). These units are older jet engine units which require this type of fuel. They run infrequently and it apparently would not make economic sense to switch fuels. In my review I found that none of the experts' studies reflected the use of kerosene in any PJM peaking plants. Instead it was assumed that these units ran on No. 2 oil, a much lower cost fuel (for the small quantities used by such units). This has the impact of understating the marginal cost of generation in the highest demand hours of the year and during other periods when transmission constraints may dictate the use these type of units. While these are high cost units, they do run enough to impact marginal costs to some degree and as peak demands increase, will be expected to run more frequently.

Finally, the experts generally reflected little or no differences in delivered fuel prices for gas or oil. It was assumed that all gas or oil units in PJM would have the same (or

[18] Mr. Bustard believes that the low level of operation of such plants negates the importance of this assumption. However, I am troubled by the question of why these plants never run in the first place. In my view, this is symptomatic of a more serious problem.

nearly the same) delivered prices (except perhaps for differences in sulphur content). A quick examination of historical data clearly suggests that substantial differences in delivered prices for such fuels do exist for a variety of reasons. A more realistic modeling would reflect the larger historical differences in delivered fuel prices. This is also important because it will tend to understate market prices in the highest cost hours of the year and thereby understate revenues received by intermediate and peaking plants.

F. Other Issues

Q. Do you have any comments regarding the fuel price forecasts presented by PECO?

A. Fuel prices have proven notoriously difficult to predict. PECO has presented the DRI and ICF fuel price forecasts. I will present the forecast prepared by the Energy Information Administration ("EIA") for consideration by the Commission as well. I believe it is important for the Commission to consider recognized forecasts prepared by independent organizations. Forecasting fuel prices is, in itself, a complex endeavor, at least as complex as forecasting market electricity prices. A change in fuel prices translates into a change in electric market price. Note that this is not intended as a criticism of the ICF fuel forecast. The ICF forecast is prepared for use in a variety of applications, and I am satisfied it is prepared independent of consideration of its impact on electric market prices.

Q. Do you have any final comments regarding modeling of market energy prices?

A. Yes. Dr. Hieronymus appears to have introduced yet another bias in his calculation of the market value of PECO plants in his variable O&M assumptions for PECO units. Examination of Exhibit No.___WHH-3 reveals that he assumes variable O&M costs for PECO coal and CT units which are generally higher than those for comparable units in PJM. This has the effect of placing PECO's units at a competitive disadvantage in the regional dispatch, thus depressing revenues generated by these units.

V. CRITIQUE OF PECO MARKET CAPACITY PRICES

Q. Are you in agreement with PECO's forecasts of market capacity prices?

A. No. I found numerous instances where PECO's experts have used either incorrect or biased assumptions which have the effect of depressing market capacity prices. These include:

1. PECO's experts have understated the installed cost of new capacity and excluded many costs including construction labor costs, interest during construction, contingencies, engineering, financing and legal costs.

2. PECO's experts have understated real fixed charge rates by excluding various taxes and due to mistakes in their calculations.

3. PECO is not consistent in the inclusion of A&G expenses, decommissioning costs, and capital additions for its own units and for competitive generators.

4. PECO's use of understated heat rates can also bias capacity costs downward in the EDS study.

Q. Please explain how the experts compute market capacity prices.

A. The process is rather simple, particularly for the PHB and ICF analysis. In both cases the cost of capacity is computed as the product of a real fixed charge rate times the cost of new combustion turbine capacity plus the associated annual O&M expenses. This represents the cost of "pure capacity" in a competitive market, under the assumption that peaking units would be added to the system in order to meet increases in demand, and that in equilibrium market prices will by necessity support enough investment in new capacity.

Q. Do the experts actually assume that only new CT capacity will be installed?

A. According to Dr. Hieronymus, with the MAPS model and his assumptions, new combined cycle units would be unprofitable relative to CTs in PJM.[19] In the ICF and EDS studies, however, the great majority of new capacity built is combined cycle. According to Dr. Venkateshwara the ICF model does not predict *sufficient additional* fuel benefits (over the spread between combined cycle and combustion turbine costs) to offset any of the CT capacity costs. The EDS model actually links capacity and energy costs (or at least is purported to do so) and in some cases does predict sufficient

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[19] Given the problems related to modeling of cycling units in MAPS that I previously discussed, this should hardly come as a surprise. I doubt if any cycling unit could make a profit under Dr. Hieronymus' assumptions. Recall also that the problem in Dr. Hieronymus' QRO study was *his* assumption that substantial new combined cycle capacity would be built in PJM despite the fact it would be unprofitable to do so. By building too much combined cycle capacity Dr. Hieronymus depressed market energy prices in his earlier study.

fuel savings from combined cycle plants to result in a net capacity cost below that of a new CT.

Q. **Based on this discussion it appears that there is a linkage between market energy prices and the costs of new peaking capacity and new combined cycle capacity. Is that correct?**

A. Yes. If there is little difference between the cost of a new combined cycle plant and a new CT, developers would find it advantageous to build the former. This would tend to reduce market energy prices, and could even result in a reduction in market capacity prices. Conversely, low market energy prices will result in a situation where the new peaking capacity is the economic choice (such as the case in the PHB study). If an understated heat rate is used in the EDS model, it can increase the profits of combined cycle units and depress both capacity and energy prices.

What is less obvious, but quite significant, is the fact that a developer could actually make an expensive mistake in the choice of technologies. For example, if lower than expected fuel prices materialize, then the added cost of a combined cycle plant might never be recovered. It should be rather clear that such investments are a rather risky proposition, certainly more risky than plants built under the traditional "obligation to pay" paradigm where utilities frequently assume that ratepayers are obligated to bear all costs of uneconomic choices.

Q. What are the key data inputs in such an analysis?

A. Naturally the capital, O&M and other costs of new CT and combined cycle generation are the key variables. The differential between these costs is also quite significant because it will largely determine the optimal mix of new peaking and combined cycle capacity. In addition, the real fixed charge rate is also quite important. This is computed from assumptions regarding the cost of capital for non-regulated power plants, tax rates, depreciation rates, etc. These basically represent the same types of inputs as one would find in any conventional utility calculation of revenue requirements, though it is optimistically assumed that in a competitive market, developers will be willing to "back-load" payments and profits. Under conventional regulation such payments have always been "front-loaded." This difference in assumed cost recovery patterns substantially increases the risks of new generation resources and should be compensated for with a higher cost of capital.

Q. Would I be correct in assuming that the experts have used the same assumptions for these input items in the current case as in PECO's QRO filing?

A. Unfortunately not. ICF has maintained its original (highly optimistic) position while PHB and EDS have substantially reduced their cost estimates for new capacity.

The table below presents a comparison of combined cycle and combustion turbine costs assumed in each of the three PECO studies between the QRO case and the current proceeding.

	Comparison of New Generator Costs ($/kW)					
Case:	ICF- CT	ICF -CC	EDS-CT	EDS-CC	PHB-CT	PHB-CC
QRO	300	450	380	640	360	655
Current	300	450	325	625	276	519

Q. Let's return to the error in the EDS QRO study related to the cost of new CT's. How did EDS correct that error?

A. EDS assumed in the QRO proceeding that new plant capital costs would remain constant in nominal terms from 1996 to 2010. This assumption was admitted to be inconsistent with the real fixed charge rate computed by EDS. EDS "corrected" this error in the current filing by assuming that the cost of new CT's would remain constant in nominal terms until only 2002. EDS accompanied this "correction" with a downward reduction in the carrying cost of a new CT as well as the previously discussed decrease in the capital cost of new plants. In the end, EDS corrected an error that PECO admitted in the QRO *understated* market capacity prices by further *lowering* market capacity prices. It is also interesting to consider that while EDS is apparently somewhat uncertain as to the cost of a new CT (cost estimates varied by 15% in the space of three months), EDS remains certain that the cost of new CT's will not increase for at least the next five years.

Q. **Did PECO's experts provide compelling documentation of the more optimistic assumptions for new plants?**

A. No. In the response to PAIEUG I-13 supporting documentation was provided for combined cycle and combustion turbine assumptions. However, this "support" provides very little support for the figures actually used. Further, the documentation reveals a rather selective procedure was used in application of the source data. For example, pages from TVA's 1995 IRP study were provided. However, this report shows a combined cycle unit capital cost of $655/kW and a heat rate of 7,000 btu/kWh. TVA projects capital costs of $487/kW for re-powering projects and a heat rate of 7,900 btu/kWh. An EIA study is also referenced. EIA projects heat rates for current combined cycle technology of 8,030 btu/kWh improving to 7,000 btu/kWh by 2010. The only heat rates approximating the sub-7,000 btu/kWh figures used by the PECO experts were found in the EIA estimates for an *advanced* technology (which may or may not be) available in the year 2000. Interestingly enough, these units were projected to have a heat rate in the year 2000 of 6,955 btu/kWh, and improving to 5,700 in the year 2010. What is really telling is the fact that EIA also projected capital costs for combined cycle units ranging from $430/kW to $620/kW and the O&M expenses shown are $27-29/kW, a level substantially *higher* than assumed by any of PECO's experts. Clearly, this demonstrates a tendency of PECO's experts to selectively apply optimistic data from a variety of sources, while ignoring the same data from such sources when it is not as optimistic.

Q. Do you have any additional comments concerning other assumptions made by PECO's experts relative to new generation?

A. Yes. Just as in the QRO proceeding, the experts are generally assuming plant reliability for new units far greater than is the case for existing utility plants. While I can accept the notion that technological improvements will take place, it is important to realize that the experts are projecting capacity costs, heat rates, O&M expenses and availabilities for new plants substantially more favorable than those of existing units. What is important to recognize is that there is a tradeoff between plant efficiency and reliability and plant capital costs. For example, plant reliability can be greatly improved by installation of redundant system for pumps, motors, computers, control system, etc. This redundancy is now common in IPP plants because they are frequently paid on the basis of kWh output. However, such redundancy increases capital costs. I am concerned that the experts have appropriated the high reliability of plants with substantial redundancies while assuming the lower capital costs of plants with fewer back up systems.

Similar comment apply with respect to heat rates. The size of the heat recovery steam generator on a combined cycle plant impacts upon the plant efficiency (heat rate) and the capital cost. Dr. Venkateshwara continues to cite the Mid-Georgia Cogeneration project as an example of a combined cycle plant with a low capital costs.[20] However, examination of the attached terms of the Mid-Georgia Cogen contract show a guaranteed contract heat rate of 8,900-9,600 btu/kWh and inflation indexed O&M expenses of $12/kW year. While the contract heat rate may not be totally representative of the actual heat rate, the Mid-Georgia project is not support for the concept of a low capital cost <u>and</u> a low heat rate. Further, the low capital recovery rate referenced for the Mid-Georgia project is also a direct result of is long-term contract to sell energy to Georgia Power, which would enable a high proportion of low cost debt.

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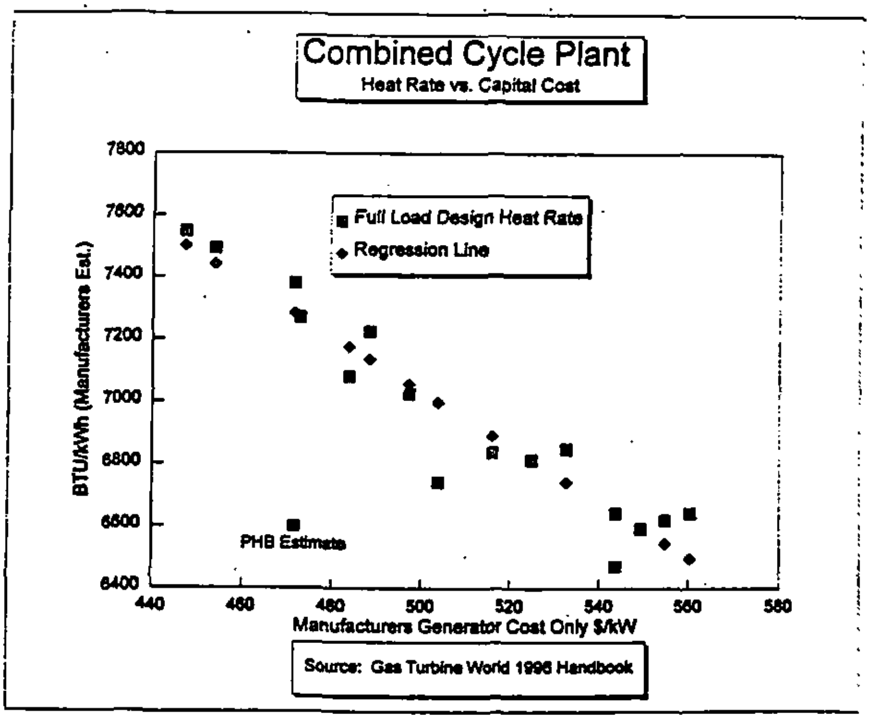
[20] This is supported by ICF's response to PAIEUG I-13.

Q. Do you have any other evidence which supports these contentions?

A. Yes. Dr. Hieronymus cites the Gas Turbine World 1996 Handbook as support for his estimate of a 6,600 BTU/kWh heat rate and $470/kW (summer rating) combined cycle plant. However, Dr. Hieronymus has selected a capital cost which is among the *lowest* figures cited and combined it with a heat rate that is also one of the lowest. Figure 3 below shows the actual relationship between heat rate and the direct generator-only costs for the plants contained in the Gas Turbine World 1996 Handbook. It demonstrates that Dr. Hieronymus selected the most optimistic figures for both parameters. He attempts to justify it under the assumption that post-2000 time frame improvements will increase plant efficiencies or decrease capital costs.



Q. Des the Gas Turbine World 1996 Handbook provide any additional insights into the problems with the experts' cost estimates for combustion turbines and combined cycle plants?

A. Yes. The publication points out in a number of instances that the cost figures presented exclude many items and represent nothing but the most basic combined cycle plant equipment costs. I will quote below a number of significant passages:

> **"These are average turnkey plant prices, reflecting the median of the price range for a 'no-frills' plant."**
>
> **"Remember, that these $ figures are designed for scoping and preliminary project assessment. They are not 'nailed down' numbers that you will actually end up paying for a new combined cycle. There are simply too many options and variable to attempt that."**
>
> **"No catalytic converters for NO_x or CO reduction. Minimum exhaust stack."**
>
> **"Does not include electrical substation or switchyard or a pipeline to bring in gas fuel, or storage or treatment for liquid (if dual fuel).[21] Administrative offices, workshops or storage building not included. No black start generator sets. Minimal operational spares."**
>
> **"For example, construction costs can vary dramatically as a function of labor rates at different site locations."**

[21] Of the excluded costs, these are the only ones PHB attempted to include. ICF apparently did not include any of these costs.

> **"Also affecting prices is overproduction at the gas turbine and steam turbine OEMs. Series-produced, inventoried machines are being offered at bargain basement prices to clear shelves."**
>
> **"These turnkey plant price levels, as noted, are for 'plain vanilla' plant equipment and services. Extended site work such as cogeneration process, steam or utility plant tie-ins are not covered, nor are extensive building, nor a large inventory of operational spares such as combustor baskets, blades and vanes, etc."**
>
> **"Also not included are the indirect or so-called 'soft costs' that can significantly increase the overall project costs."**
>
> **"These soft costs would include interest during construction, financing and legal fee, licensing, permitting, insurance and bonding, workman's compensation, sales tax, extensive inland freight, owners costs and overhead, and, finally, project contingency funds."** (Gas Turbine World 1996 Handbook, pages 1-12 to 1-18)

Of the numerous omissions of costs from the PHB analysis, I believe that interest during construction would be the most significant. It could easily take two years to three years to site, license, finance, construct and test a project. Even assuming minimal short term interest rates of 5%, this could add 10-15% to the total project cost. Further, the current oversupply of turbines referenced above could not be expected to last for the next 30 years. On net, it appears that Dr. Hieronymus has made some exceptionally optimistic assumptions in his derivation of the combined cycle unit heat rates and capital costs, that are not supported in his source documents.

Q. Do similar comments apply in the case of the combustion turbines costs used by Dr. Hieronymus in computing his capacity credits?

A. Yes. The Gas Turbine World 1996 Handbook makes a number of comments regarding the costs of combustion turbines similar to those above. Dr. Hieronymus also used figures from the same publication to estimate the cost for the turbine equipment to be around \$210/kW (summer rating). He then increased that cost by about 30% to \$276/kW to reflect utility tie-ins, infrastructure, etc. However, it appears that Dr. Hieronymus missed the fact that the cost estimates provided are stated to be "equipment costs only" and do not include *any* construction related costs such as labor, installation, assembly and, etc. In Dr. Hieronymus' calculation of combustion turbine plant costs shown in PAIEUG I-13, he has provided no allowance for such costs. This exclusion of labor costs is in addition to his exclusion of the above referenced siting, licensing, financing, engineering, legal and etc. costs.

Q. Does the Gas Turbine World 1996 Handbook cast any further doubt on Dr. Hieronymus' cost estimates?

A. Yes. The publication indicates that in addition to the cost for turbine equipment, other costs (those referenced above) can easily increase the final cost of a project by 50-100%.

However, Dr. Hieronymus' allowance of only 30% is substantially less than suggested in the document Dr. Hieronymus purports to rely upon.

Q. Do the ICF estimates also suffer from some of these same defects?

A. Dr. Venkateshwara's cost estimates start at $450/kW for a combined cycle plant. This is even less than the figure Dr. Hieronymus started with before adding his limited allowances for a gas pipeline, switchgear, land, etc. I believe that the ICF figures do not reflect *any* of the added costs that Dr. Hieronymus included in his study or any of the other costs, discussed above, that Dr. Hieronymus excluded. In addition, Dr. Venkateshwara indicated to me during a telephone conversation in the QRO proceeding that his combined cycle cost estimate was an overnight cost. This means that construction costs exclude any escalation or interest during the construction period. I have no confidence in the ICF cost estimate for a combined cycle plant.

Q. Are reduced capital costs and heat rates the only instances of problematical changes to input assumptions?

A. No. The comparison of real fixed charge rates is also revealing. PHB has consistently used a 12% real fixed charge rate. ICF actually increased the real fixed charge rate (for

Combined Cycle plants) from 10% in the QRO to 12.7% in this case.[22] EDS *decreased* its real fixed charge rate from 14.7% to 12.8%. It is important to realize that the main component of the calculation of market capacity prices is the product of the cost of peaking capacity and the real fixed charge rate. In the end ICF did not change its calculation of the ownership cost of peaking capacity ($38.10)[23]. PHB reduced its estimate of the cost of CT ownership from $43.20/kW-year to $33.12/kW-year or by almost 25%. EDS reduced the annual ownership cost of a new CT from $55.86/kW to $41.60/kW also nearly 25%.

Q. Do you find any other inconsistencies in the experts assumptions regarding the computation of the real fixed charge rates?

A. Actually, these computations are totally inconsistent. Dr. Hieronymus and EDS assume, for example that investors will require a 12% return on equity for a new combined cycle plant, while ICF assumes 14%. Interestingly enough, EDS used the 14% ROE figure in the QRO proceeding. It is also rather interesting that the cost of capital assumed by

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[22] In the end, however, this change in input assumptions has virtually no impact on the ICF results because ICF did not calculate capacity costs based on a combined cycle plant. However, by using a low cost for combined cycle plants, ICF depresses market energy prices because its mix of new generation is weighted heavily towards these more efficient plants.

[23] ICF used a 12.7 real fixed charge rate for CT's in the QRO and in the current case. In the QRO ICF used a 10% rate for combined cycle plants.

EDS and PHB (12%) is only slightly above the 11.6% ROE that PECO's expert, Mr. Brennan, recommends for PECO, a regulated utility, that may be afforded the financial luxury of stranded costs recovery.

Q. **Does PECO's cost of equity expert, Mr. Brennan, have any opinion regarding the cost of capital for a new generator in a competitive market?**

A. Not that I can determine. In PAIEUG I-12 we asked if it was PECO's opinion that an IPP in a competitive market would have a higher or lower required ROE than PECO's current required ROE. MR. Brennan's answer, attached as Exhibit No.___(RJF-4) was that PECO could not agree or disagree. In other words, Mr. Brennan has stated he simply does not know!

Q. **Are there other problems with the experts' calculations of real fixed charge rates?**

A. Yes. All of the experts' calculations contain outright errors or omissions which understate the market price of new capacity. Both EDS and PHB assume only a 35% composite tax rate, while ICF assumes a 41% composite rate. Neither PHB nor EDS have allowed for <u>any</u> provision for state income taxes for new generators. This clearly understates the market price for new capacity. I pointed out this problem in my QRO testimony and it was never addressed by any of PECO's experts, nor was it corrected in this case. There is no explanation for this mistake because the other PJM states (Delaware, Maryland and New Jersey) all have state income taxes nearly as high as Pennsylvania's.[24] What I find rather interesting is that PHB and EDS "updated" their studies with new (and substantially lower) capital costs for peaking plants, and EDS even reduced its assumed equity return, yet neither firm corrected this obvious tax rate error, even after it was pointed out many weeks ago.

The tax rate error is not the only problem with the real fixed charge rate calculations. ICF totally ignores property or other taxes in its calculation, while the EDS study computes the annual return requirements assuming an end of year convention. This understates the cost of ownership because it assumes investors will never earn a full return on their investment. Thus, the 12% ROE assumed by EDS is never actually achieved. PHB correctly assumed an average year convention.

In addition, there are a number of other inconsistencies in the experts' real fixed charge rate calculations related to book lives, property tax rates and inflation assumptions. When only the most blatant "errors" noted above are corrected (PHB's and EDS' omission of state income taxes, ICF's omission of other taxes, and EDS' incorrect end

24 In addition, I understand that a gross receipts tax of 4.4% now applies to out-of-state generation.

of year convention) the real fixed charge rates rise significantly: from 12.0% to 12.5% for PHB, from 12.7% to 13.3% for ICF and from 12.8% to 13.5% for EDS. Lest the commission think I am nitpicking, I would point out that for PHB this correction alone amounts to an increase in the market value of PECO's assets by roughly $100 million!

Q. Do the experts include <u>all</u> of the costs in their analysis of new generators that Mr. Hill included in his calculation of the market value of PECO's generators?

A. No. Mr. Hill includes state income taxes, property and other taxes, A&G expenses, decommissioning expenses and capital additions for <u>all</u> of PECO's generators. None of the experts include decommissioning costs or capital additions. In addition, only the EDS calculation appears to allow for A&G expenses (which may be built into the real fixed charge rate via higher property tax and insurance rates), and as noted above, PHB and EDS ignored state income taxes while ICF ignored property and other taxes.

Q. Do you believe that all of these costs should be included?

A. These should be treated equally in case of PECO and new generators. Mr. Kollen has recommended that I exclude fossil decommissioning costs from the computation of PECO's expenses. Thus, I would also exclude these costs from my analysis of new generators. However, new generators will require capital additions[25], will require supporting A&G expenses and will most certainly be required to pay state income taxes, property and other taxes.

Q. Are Mr. Hill's projections of O&M expenses for PECO's existing CT's consistent with the experts projections of these costs for new CT's?

A. No. Mr. Hill projects O&M expenses for PECO's existing CT's of approximately $12/kW year (96$). The experts uniformly project O&M expenses for new CT's of $2/kW year. There is no explanation for this discrepancy.

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[25] This is supported by PECO's response to PAIEUG I-13.

VI. CRITIQUE OF PECO MODELING METHODOLOGIES AND RESULTS

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

A. I have identified a number of problems with the modeling methods applied by PECO's experts. These stem more from the application (or misapplication) of the models themselves than from input assumptions. In this section of my testimony I will address the following problems I have uncovered in PECO's models and discuss the implications for market prices:

1. The models fail to perform realistic simulations of random generator outages.

2. The GE MAPS model, as applied by PHB, provides unreliable estimates of marginal costs due to the use of only one Monte Carlo simulation.

3. The modeling of pumped storage resources is unrealistic.

Q. Please begin.

A. My major concern deals with the methods used by the experts to simulate the impact of random generator outages on market prices. The ICF and EDS models use what is known as the capacity deration method. This approach would derate the capacity of a 1155 mW generator, such as Limerick I, to 982 mW a unit to account for the fact it may be on a forced outage 15% of the time. The problem with this representation is that peaking units run largely in response to the full forced outages of baseload plants. Assuming a 982 mW Limerick plant that is available 100% of the time will not result in the same amount of peaking generation as would occur in the real world, where an 1155 mW unit is available 85% of the time and a 0 mW unit available 15% of the time. This type of representation has been well known to experts within the industry as causing underestimates of peaking generation requirements (and therefore marginal costs) for decades. It was this very type of problem that lead to the creation of probabilistic models such as PROMOD more than twenty years ago. Even the Ebasco Marginal Cost model that I developed in 1980 used a Monte Carlo (probabilistic) technique to provide better estimates of marginal costs and reasonable amounts of generation from peaking plants. It should come as no surprise that, in the ICF and EDS models, PECO's CT's run little or not at all.

Q. **How do the PECO projections of generation for peaking plants compare to actual experience?**

A. Quite poorly. For example, in 1995 PECO's combustion turbines produced 173 gWh of energy and ran with a 2% capacity factor. In the EDS simulation these units never run over the period 1999 to 2014. The ICF and PHB projections do little better, showing average generation of 5 gWh in 1999 for ICF and 15 gWh for PHB. Given that loads are expected to increase and reserve margins to decline from 1995 to 1999, this substantial drop in peaking generation is rather hard to understand. While this may seem like a minor point, the added margins occurring during these hours when peaking plants are running will produce a noticeable increase in the market prices paid to baseload plants.

However, the problem is not limited to combustion turbines. In 1995 the Eddystone gas units ran with a 30% capacity factor. The EDS projection shows the plant would never run from 1999 to 2001, or from 2006 to 2025. For the period 2002 to 2005 PMDAM projects a 2% capacity factor for these units. These results occur despite the optimistic assumption that Eddystone is fueled 100% of the time with natural gas.[26] ICF projects a 6% capacity factor in 1999, and over the period 2000 to 2025 capacity factors never exceed 12%. Even Mr. Bustard's PROMOD IV study (intended as a check on the reasonableness of the other models) predicts far less generation in 1999 for PECO's CT's and oil units than actually occurred in 1995.

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26 I suspect that at least part of the problem may lie with the EDS assumption that units will not run on negative cycle days.

Finally, even though the PHB study projects more realistic operations for the Eddystone 3 and 4 units, it completely fails to provide a reasonable projection of the operation of Muddy Run, PECO's pumped storage plant. The PHB projection shows the Muddy Run plant operating at only a 4% capacity factor in 1999 compared to the 1995 actual capacity factor of 22.5%. PECO should recognize that its models are vastly understating the amount of peaking generation needed in PJM.

Q. **Do you have any other concerns about the MAPS model?**

A. Most definitely. Unlike the EDS and ICF models which rely on the deration technique to model random outages, MAPS uses a Monte Carlo simulation method. This is conceptually a sound approach and if properly applied provides an excellent means of modeling generator outages. Unfortunately, the MAPS model is apparently so cumbersome to operate that the number of Monte Carlo simulations had to be limited to one per year. This completely invalidates the use of the MAPS model.

Q. **Please explain what you mean by a Monte Carlo simulation.**

A. Generator outages occur at random. To simulate these outages, one approach is to simulate a series of scenarios drawn at random (each reflecting possible outages for various generators) and then average the results.

Q. How is that done?

A. I'll provide a simple example of how the calculation could be done. Assume Limerick (and other generators) have forced outages 1/6 of the time. This means that on any given day if you roll the dice and get one through five you would assume Limerick is up and running. If you roll a six Limerick is down. This process might be repeated for each unit, each day. At the end of the year you would compute production costs for this scenario and then repeat it a number of times averaging the results. The problem is that PHB instructed the MAPS program to limit the roll of the dice to once per year per unit. I first learned this during my meeting with the PHB representative. Exhibit No.___(RJF-5) is PHB's response to PAIEUG Data Request No. VI-8 confirming my understanding of the approach used in MAPS. It reveals that in the PHB simulation MAPS randomly selected a single set of weeks at random intervals during the year to model each unit's forced outages. I find this highly questionable.

Q. Why?

A. Over the years I have developed several Monte Carlo models. In my experience a reasonable result cannot be developed on the basis of one simulation. I do not agree with the assumption of Mr. Bustard and PHB that the large number of units modeled in PJM and the surrounding regions negates any necessity to run a greater number of simulations. The primary reason for this is that PJM is dominated by nuclear capacity. The thirteen PJM nuclear plants provide 12,913 mW of capacity. In some cases, these units also have relatively high outage rates compared to other types of plants. A random simulation where a disproportionate number of these plants are either on simultaneous outages (or where simultaneous outages fail to occur) will have a substantial impact on the operation of the highest cost plants in the pool, and, therefore, marginal costs. Thus, the random outage of the several hundred small units in PJM are not nearly as significant as the outages modeled for thirteen large nuclear plants. While several hundred rolls of the dice may well produce an average close to 3.5, thirteen rolls of the dice could stray far from the expected value. It is these thirteen rolls of the dice for the nuclear plants that have a disproportionate impact on marginal costs in MAPS.

Q. Do you have any evidence to support your position on this matter?

A. Yes. As will be explained in more detail later on, I have developed both conventional probabilistic and Monte Carlo-based production cost models to simulate market prices in PJM. I developed a set of input assumptions for my Monte Carlo model (designed to simulate pumped storage operation) which I used to estimate the annual average marginal costs for PJM under assumptions paralleling those used by PHB in MAPS. I ran the model for a series of cases with only 1 simulation per unit per year. The results, shown on Exhibit No.___(RJF-6) reveal that even with a simulation of nearly 400 separate generators in PJM, cases limited to one Monte Carlo simulation could produce variations from the mean of as much as \$3/mWh or 15%. At best, we can assume that Dr. Hieronymus' simulations fall somewhere in a band that is 15% or\$3/mWh wide. PECO sells about 40 million mWh per year. This means that each mill is worth about \$40 million. Dr. Hieronymus figures could be off by more than \$100 million per year! There is really too much at stake in this proceeding to tolerate this level of uncertainty.

Q. **You have demonstrated Dr. Hieronymus' study is unreliable. However, that doesn't necessarily imply it is biased. Are there any reasons to suspect that Dr. Hieronymus' single simulation technique produces a result lower than might be obtained by taking the average of a large number of cases?**

A. Yes. First, notice that in Mr. Bustard's comparison of the PROMOD IV, ICF, EDS and MAPS models, the MAPS study provided the lowest estimate of marginal energy costs. In addition, it is important to realize that the distribution of marginal cost results will not be symmetric about the mean. Marginal costs increase substantially when peaking units run in response to multiple contingencies (particularly those of nuclear plants). While these scenarios are generally unlikely, they occur often enough to substantially impact marginal costs. A large sample of cases would likely contain a great many "low" cost scenarios, with only a few "high" cost scenarios. An average of many cases would reflect the relative likelihood of each scenario. However, it is far more likely that a random draw of only one out of the sample will generate a "low" result.

Q. **How might Dr. Hieronymus correct for this problem?**

A. The solution is quite simple. The only practical approach is to run MAPS for at least 100 simulations. [See again Exhibit No.____(RJF-6).] Given this devastating problem and the numerous other infirmities in Dr. Hieronymus' study, I believe that the Commission should dismiss the PHB study from further consideration.

Q. **Are there any other serious problems with the experts models?**

A. Yes. None of the models employed appears capable of a realistic modeling of pumped storage plants. PECO's 880 mW Muddy Run plant is a significant capacity resource which demands a realistic valuation. Based on my discussions with the Company and their consultants, as well as PECO's response to data requests, it is clear that the pumped storage simulations employed fail to capture the daily chronological dynamics of pumped storage operation. The ICF model, for example, would allow pumping in October to offset generation in May. The EDS model has similar problems. Clearly this type of representation cannot provide a realistic assessment of Muddy Run or any other pumped storage plant. As was already discussed, there is clear evidence of a problem with the MAPS modeling of Muddy run because it predicts only a 4% capacity factor for the unit in 1999. Also, in my own simulations I have shown that the use of the erroneous PHB heat rates seriously reduces operation of pumped storage units.

Q. What are the conclusions you have drawn based on this review of PECO's market price studies?

A. This type of analysis is dependent upon data and computer models. I have shown that nearly all of the most crucial input data used by PECO's experts is either wrong, biased, inconsistent with other figures from the same source, or highly suspect. The models appear no better and produce results which are contrary to actual experience, or demonstrably unreliable. The PUC simply cannot have *any* confidence in the PHB or EDS studies. While the ICF model and data are marginally better, in my view, the ICF assumptions in many cases are either biased, overly optimistic or simply undocumented.

Finally, the PUC should recognize that ICF fuel price forecast is lower than the DRI forecast used by EDS and PHB and as previously discussed, the unrealistic capacity cost assumptions for combined cycle plants used by ICF results in a downward bias on market energy prices.

VII. CORRECTED ESTIMATES OF PECO GENERATION STRANDED COST

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

A. In this section I present a calculation of market value and stranded costs based on correcting the assumptions of the PHB and ICF studies. I further present my own independent market price forecast using the EIA fuel price forecast.

Q. How have you modeled PJM market prices?

A. I have used my own production costing models to simulate PJM market prices. I have independently assembled all of the data required for this simulation from publicly available data sources. Rather than clutter my analysis with numerous undocumented ad-hoc adjustments, I have preferred to stay as close as possible to the figures published in the original source documents.

Q. Please discuss the models which you have employed in this project.

A. My analysis rests on two basic models: a Probabilistic market price simulation model and a Monte Carlo pumped storage simulation model. These models provide the basic simulation results for my studies. I will refer to these models as the "Probabilistic" model and the "Monte Carlo" model.

Q. **Have you used these models previously in regulatory proceedings or consulting projects?**

A. Yes. The Probabilistic model contains the probabilistic production cost engine which I have used in numerous regulatory proceedings before a variety of Commissions since 1984. I most recently applied this model in preparation of my testimony in the Commission's Investigation on Restructuring in 1995, where I used it to simulate a hypothetical Pennsylvania spot energy market. Exhibit No.___(RJF-7) is a summary of regulatory proceedings where I have used the model in the past and a list of comparison studies I performed to "benchmark" this model with a comparable utility Company model. I have successfully benchmarked this model with nearly every major utility production cost model in use in the industry today, including PROMOD III, PROSCREEN, EGEAS, UPM and several others. The production costing engine used in this system allows for a highly variable level of detail. I have found that by increasing the level of detail to that comparable with the most significant assumptions used by the utility model, I am able to replicate the results of far more detailed models. In this proceeding I will demonstrate the ability of these models to reasonably replicate the results of the GE MAPS program as implemented by PHB, the EDS PMDAM model and the ICF IPM model.

Q. Why is this replication of results between models useful?

A. There are two reasons. First, it enables one to maintain confidence in a model if its results track those of comparable models. Second, it provides a powerful diagnostic tool. By replicating the results of the various models in this case I was able to discover the significance of the erroneous heat rate assumptions in the MAPS model, for example, and to demonstrate similar problems in the ICF and EDS programs or data.

Q. Please describe the Monte Carlo model.

A. This is a more recent development. It was originally intended to model the economics of pumped storage plants using a probabilistic (Monte Carlo) technique, and the same data base as the probabilistic model, but with a higher level of detail. The model enables one to estimate hourly marginal costs for a given region, and then makes the economic determination of whether to utilize a pumped storage unit on a given day based on the ability to offset high cost generation with lower cost energy (recognizing pumping losses) at night. The model maintains the chronology of daily loads and enables a more realistic modeling of pumped storage plants than other resources. The model outputs are then used to develop and input load shape for the Probabilistic model, but can also be used to develop chronological marginal costs. The original application of this model was to examine the economics of the Rocky Mountain pumped storage plant for a project I am performing on behalf of the Georgia Public Service Commission Staff.

Q. **How do you define the regional energy market in your analysis?**

A. I limited my modeling of specific loads and resources to the PJM region. There is ample evidence, as I have already discussed, that demonstrates it is appropriate and reasonable to confine the review to PJM.

Q. **Did you find it necessary to model transmission constraints within PJM?**

A. No. I found the analysis performed by PECO for the PJM Restructuring Proceeding at the FERC, the testimonies of Dr. Hieronymus and Mr. Bustard in this case, and that of Dr. Scott Jones in the PP&L proceeding, compelling evidence of the lack of long term significance of transmission constraints in PJM.

Q. Please describe what you mean by a probabilistic modeling.

A. As discussed earlier, random forced outage of large generating units can result in substantial increases in marginal generation costs. A probabilistic simulation computes the expected value of production costs (both total and marginal costs) by computing the probability weighted average of all possible generator outages. The original algorithms used to calculate probabilistic production cost results were described in an IEEE paper by Booth in 1970.[27] A Monte Carlo simulation does the same thing by developing a series of simulations of a large number of possible outage states and computes the average result from these trials. Both techniques can be quite accurate. Probabilistic techniques are computationally more efficient, but lose the chronological character of the system dispatch, that is quite important for modeling of pumped storage, for example. Monte Carlo techniques are not as efficient, and the operation of individual steam plants is more difficult to capture. In my simulations I use the Probabilistic model to compute revenues and market prices for all plants except pumped storage units.

Q. Provide a simple example that explains the differences between the two techniques.

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27 Power System Simulation Based on Probability Analysis: RR Booth, presented for publication to the IEEE Power Committee, April 29, 1970.

A. Assume you wanted to know the expected value of a single roll of the dice. The probabilistic approach sums the probability of each possible outcome (one-sixth) multiplied by the outcome (from one to six). For a fair dice, the expected value is 3.5. In a Monte Carlo simulation one rolls the dice a large number of times and averages the result.

Q. **What are the data requirements for your modeling?**

A. My modeling requires the same types of data as required in the Company's market price simulations: hourly load shapes, peak demands and energy forecasts, unit capacities, equivalent forced outage rates and plant maintenance requirements, maintenance schedule information, generator fuel types, prices, and escalation rates, heat rates and operating constraints, if applicable. In addition, I require data for non-utility generators, imports and exports from other regions. Finally, I require data regarding unit up ratings, down ratings, retirements, additions, as well as data for new generation resources.

Q. **Please describe the data sources you relied upon.**

A. I obtained the necessary data from publicly available sources as show in the table below.

Data Requirement:	Source
8760 Hourly Loads	Loads Filed in FERC Form 714
Load Forecast	MAAC Form OE-411
Unit Availability Data	NERC GADS
Unit Capacities	MAAC Form OE-411
Unit Heat Rates	EIA Form 860
Unit Fuel Base Fuel Cost	FERC Form 1
Unit Capacity Changes	MAAC Form OE-411
Fuel Price Escalation Rates	EIA Annual Energy Outlook 1997
Unit Fuel Type	MAAC Form OE-411, FERC Form 1
Non Utility Generators	MAAC Form OE-411
Maintenance Avoided Periods	Supporting Companies' Proposal
Regional Imports and Exports	MAAC Form OE-411

Q. **How many generators did you model in PJM?**

A. I modeled more than 360 individual generators in addition to the pumped storage plants in the region and a large number of capacity additions, IPP's and imports.

Q. **Do these sources provide all of your data requirements?**

A. Virtually all of the data I require comes from these sources. In a very few cases (such as hydro plants for example) some of the data I used came from utility sources. For a very small number of generators owned by public power agencies, I estimated fuel prices based on delivered prices for other plants in the same control area.

Q. **Did you make any adjustments to this data?**

A. The only adjustments made to this data was to increase the availabilities of PJM BWR's in excess of 1000 mW (Peach Bottom, Limerick and Hope Creek) to reflect the higher levels assumed by PECO in its filing. This resulted in an average nuclear capacity factor for PJM nuclear plants of around 75%, consistent with the historical availability of these plants, though below recent averages. I also reflected PECO's planned up rating of Limerick. I did not reflect retirements unless they were shown in the OE-411. My simulations support higher market prices than PECO's suggesting it would be advantageous to avoid some of the economic retirements PECO assumes for its own units.

Q. **Did you make any other adjustments to this data?**

A. For all practical purposes the answer is no. My intention was to only change data from these sources when the original source data was clearly wrong or inappropriate for the model. An example of data I did change was for the Hay Road combined cycle plant. In the EIA Form 860 it has both CT units and a waste heat steam generator. The waste heat generator was shown as having a heat rate of zero because it captures the heat from the CT's. I modeled this unit by computing the full load heat rate for both the CT's and the waste heat generator combined.

Q. How did you determine the mix of new generators?

A. I developed a method to determine the economic mix of capacity additions similar to the approach Dr. Hieronymus applied in the GE MAPS model. I included a 50 mW combined cycle plant in the mix and added combined cycle generation to the extent required to meet the assumed PJM 18% reserve requirement. If the incremental cost of a combined cycle plant over a CT was unprofitable, I replaced combined cycle generation with combustion turbines. Otherwise, I assumed combined cycle plants would be the resource of choice in PJM. While this may seem difficult, in practice it isn't because usually under a given fuel price or unit cost scenario, one of the two technologies is the preferred choice.

Q. Is there any fundamental difference between your modeling approach and that applied by PECO's experts?

A. Yes. The modeling technique I employ allows one to develop bidding strategies for classes of units. For example, for each utility I categorized units by fuel types: nuclear, coal, oil, gas, hydro and other. This modeling techniques allow for the testing of bidding strategies such as bidding all gas fired units at multiple of incremental costs. The original intention of this modeling method was to test for market power (i.e., the ability of a supplier to profitably increase prices above marginal production costs). In this case the technique was useful in comparing the impact of using incremental rather than the average full load heat rate as the basis for bidding into the pool. Thus, it afforded a method to simulate the operation of Dr. Hieronymus' incremental heat rates in MAPS, as well as the average heat rates used by ICF.

Q. How did you verify the results of your modeling?

A. I decided that the best approach to use would be to develop input assumptions for the most critical differences between my own assumptions and those of PECO's experts and attempt to recreate the results of their modeling studies.

Q. **Please describe this process.**

A. First I developed a basic set of generator inputs from my own input data base. The only substantive change in this database was that historical differences in delivered fuel prices were eliminated for gas and oil units, the kerosene fueled units were assumed to run on No. 2 oil and dual fuel units were assumed to run on natural gas alone.

Next I developed fuel price escalations from the DRI and ICF forecasts. Finally I developed factors to relate the heat rates used in the MAPS and EDS models to those I obtained directly from the Form 860. For ICF this step was not necessary. Next, I input each expert's individual assumptions relative to the costs and performance of new combined cycle and combustion turbine units, and used load data appropriate for each model. For example, Dr. Hieronymus used the MAAC 1994 load forecast while EDS and ICF relied on the 1995 forecast. I then simulated the model to arrive at an initial capacity mix. Next a pumped storage simulation was performed to reflect the projected operation of the pumped storage plants based on the preliminary capacity mix. Once the pumped storage schedules were determined in the Monte Carlo program I re-simulated the probabilistic model with the final adjusted loads. The final simulation generally confirmed the optimality of the preliminary expansion plan. For the PHB assumptions CT capacity was the more economic choice, while the ICF and EDS assumptions generally dictated the addition of new combined cycle plants. My expansion plans were generally similar to those developed by PHB, ICF and EDS.

Q. **What are the results of these simulations?**

A. I was able to track the results of the PHB, EDS and ICF models reasonably well. Exhibit No.___(RJF-8) summarizes the results of this comparison and indeed demonstrates that I am able to use a single model and generator data base and predict the results of the experts' models changing only fuel prices, and input assumptions related to new capacity additions.

Q. **Do you believe these results indicate general agreement between your model and the PECO models when comparable assumptions are used?**

A. I am satisfied with these results. I could have spent a great deal of time on attempting to refine these simulations, however, I was more interested in performing market price simulations than comparisons to models that use erroneous data. I am convinced that resolving any remaining differences which remain between these models are simply not worth pursuing. In the case of the MAPS model I am also convinced that it would be a waste of time to try to refine the benchmark any further given the inherent unreliability of PHB's use of one Monte Carlo simulation. I would note again that Mr. Bustard's comparison of the four models (including his 1999 PROMOD IV study) reveals that MAPS produces the lowest market prices. Thus, I am not troubled by the disparity between my 1999 result and that from PHB's MAPS study.

Q. **Does the standard of comparison applied by Mr. Bustard in his PROMOD IV analysis support the reasonableness of your model?**

A. Yes. Mr. Bustard was satisfied that the four models he compared for 1999 were producing comparable results. These studies produced a market energy price range of $21.1 to $23.2/mWh. This is a variation of $2.1/mWh or 10%. In virtually every case my figures fall comfortably within this range and are generally much closer than that.

Q. **Why do you compare the total market price results (energy plus capacity) for the EDS model while you compare energy only for the other models?**

A. My energy only comparison with the EDS model is also excellent. The EDS model is a more dynamic model than the ICF or PHB studies in that it links capacity and energy prices. I wanted to insure that I could correctly model this relationship (albeit with the erroneous EDS data assumptions). The other studies do not model this linkage. Thus, the comparison was limited to energy prices only.

Q. Let's turn now to your own results. First of all, you have been fairly clear that the most crucial assumptions relate to the cost of new generators. What were your assumptions?

A. I have already discussed a number of the problems related to the other experts capital cost, heat rate and real fixed charge rate assumptions. I have developed what I consider to be reasonable inputs based on correcting the most obvious flaws in the other experts' studies.

Q. What capital cost did you assume for combined cycle plants and combustion turbines?

A. As noted above, Dr. Hieronymus estimate of $519/kW excludes a number of significant costs. In the end, I believe that the Gas Turbine World figures and many other estimates support a total plant cost of at least $595/kW. This is only about 15% over the PHB estimate of direct cost of the generator and the utility tie-ins. This represents an allowance for the above listed excluded costs such as interest during construction, legal fees, siting, licensing, project contingencies, more normal market conditions, etc. This represents a "plain vanilla" cost only and does not provide an allowance for the extra redundancies and operational spares needed to insure availabilities in excess of the levels achieved by normal utility plants. In the PP&L case, Dr. Jones also estimates the cost for a new combined cycle plant of $595/kW and new gas-fired CT's of $338/kW.

PHB estimated a combustion turbine cost of $276/kW for an oil fired CT. For a gas fired CT, there would be substantial cost for pipeline and I see no reason to dispute Dr. Jones' estimate. For an oil-fired CT, I include additional costs for interest during construction, contingencies, and the depletion of over supplies of such units, etc. as discussed earlier. I used $300/kW to reflect these added costs. This is supported by the $300/kW used by ICF and the $325 used by EDS. It is also substantially below the cost of recently completed plants such as Georgia Power's McIntosh plant which was certified by the Georgia Commission at $378/kW and completed at a cost of $321/kW.

For combined cycle plants, I consider the $450/kW estimate by ICF to be overly optimistic. This figure is an overnight cost and apparently does not include any interest during construction, switchgear, gas pipeline costs, electrical transmission, land or other infrastructure costs. PHB's analysis starts with a turnkey capital cost of about $470/kW (summer rating) but inclusion of the above referenced costs increases its estimate to

\$519/kW. However, this figure is inconstant with the heat rates used by PHB, and, as noted above, excludes a great many significant costs. I believe this estimate is the lower than any recently completed plant. It is also lower than the current EDS estimate, not to mention the estimates of PHB and EDS in the prior case. I believe the \$595/kW is an extremely conservative estimate and note that it falls comfortably within the range of recently completed plants and the PHB and EDS QRO case estimates.

Q. What real fixed charge rate did you assume?

A. For combustion turbines I assumed a 13.34% rate based on the ICF assumptions corrected for inclusion of property and other taxes. For combined cycle plants, I am concerned that the longer lead times and higher capital costs of such plants, and the far greater susceptibility to fuel price swings makes these riskier endeavors, particularly to the extent that fuel cost savings are needed to repay the added capital costs. However, I still used the same 13.34% real fixed charge rate. The primary difference between this figure and the PHB figure is in ICF's use of a more conservative capital structure that I believe is justified by the added risks of building plants outside of the ordinary regulatory environment and the back-end loading of the capital recovery factor. Once again, this figure is lower than the current EDS figure (once the tax rate and other errors are corrected) and substantially lower than EDS' January 1997 estimate.

Q. What heat rates did you use?

A. I assumed a heat rate of 7,000 btu/kWh. This figure is also consistent with Dr. Jones' estimates in the PP&L case. However, I believe this to be an optimistic estimate.

Q. Please discuss the 7,000 btu/kWh heat rate used for combined cycle units in more detail.

A. This number is quite optimistic for several reasons. First, the capital cost assumptions underlying this figure are consistent with a higher full load heat rate based on current technology. Thus, it reflects a certain amount of progress in the years ahead. In addition, my simulations indicated that the combined cycle plants would be expected to cycle frequently and would experience declining capacity factors in the years ahead. Thus, I believe it is reasonable to increase the operational average heat rate above the full load heat rate to reflect the prospect of operation at times below full load. Use of the 7,000 BTU/kWh figure in my model would actually be consistent with an even more efficient unit in the future running in a cycling mode. To my knowledge, this figure is lower than the most efficient currently operating utility plants in the field, and is lower than the figures used by at least one of PECO's experts in the QRO proceeding. Finally, it has generally been assumed that combined cycle plants will run exclusively on spot natural gas. However, this would require the use of higher cost contract gas, or dual fuel capability. In either case, the average cost of energy from a combined cycle plant is likely to substantially exceed the level for spot gas (based on the 7,000 btu/kWh) heat rate, even if efficiency gains for such units take place in the future. As a result, this heat rate is entirely consistent with improved efficiencies in future plants once cycling and possible gas supply interruptions are considered.

Q. **Were there any other important data items you used?**

A. I increased the combined cycle and CT O&M expenses to include additional costs for capital additions and A&G expenses. The figures I used are consistent with those used by Mr. Hill for its existing CT's and the capital additions for CT's estimated in the ICF's response to PAIEUG I-13. Otherwise, my O&M expense estimates for new plants are about the same as PECO's.

Q. **What discount rate did you use?**

A. I used 7.6%. This figure is consistent with the PUC's final order in PECO's Securitization case.

Q. Are there any other adjustments to your market value calculation?

A. Yes. As discussed by Mr. Kollen I have excluded fossil decommissioning expenses and reduced nuclear decommissioning.

Q. In the QRO proceeding you excluded Salem. Do you include Salem in this case?

A. Yes, despite the fact that the situation with Salem is little more clear today than at the time I filed my QRO testimony. This amounts to an increase of around $800 million in PECO's stranded cost allowance for a plant that is now shut down. I also accepted PECO's Salem O&M estimates, despite the fact that they greatly exceed those of Limerick and Peach Bottom on a dollar per kW basis. PECO clearly has the opportunity to cut these costs in the future and reduce its stranded cost exposure.

Q. Please describe the results of your analysis.

A. Exhibit No.____(RJF-9) summarizes my estimate of market prices and PECO's stranded costs under the EIA fuel price forecast. I estimate a total market value for PECO's generation assets of $4.81 billion. This results in a total stranded generation cost of $1.88 billion.

Q. **Have you had the opportunity to correct the PECO DRI and ICF fuel forecast studies?**

A. Yes. Using my market value modeling and the ICF and DRI fuel forecasts produces substantially lower stranded costs than is the case under the Company's modeling. In order to provide a range of estimates, and illustrate the severity of the problems in the PHB study, I prepared a scenario that corrected only the most blatant errors in the PHB analysis. In this scenario, I used the $276/kW and $519/kW capital costs for combustion turbines and combined cycle plants and the same heat rates as used by Dr. Hieronymus. I also used a 12.5% real fixed charge rate, based on inclusion of state income taxes in the PHB calculation. I further included the A&G expenses, and capital addition costs of new generators. Finally, I used my own production cost model results (and the DRI fuel forecast), however, I did use an estimate of incremental heat rates for must-run coal fired units to set bids, as discussed earlier. For coal units, I set the bid heat rates equal to 98% of the EIA full load heat rates. While I do not agree with a great many of the assumptions in this scenario, and consider even the items specifically adopted as overly optimistic, I believe that this run provides an alternative scenario that the PUC can consider to represent the minimum necessary corrections to Dr. Hieronymus study. Under the corrected DRI forecast I estimate total stranded costs of $ 2.49 billion, as is shown in Exhibit No.___(RJF-10).

Finally, I performed a scenario using my own assumptions, but with the ICF fuel price forecast. Under the corrected ICF forecast I estimate total stranded costs of $1.3 billion. [See Exhibit No.___(RJF-11).]

Q. What market price forecast do you recommend?

A. I recommend that the Commission utilize the EIA forecast. This represents the mid-point of my three studies. I have built many conservatisms into my study, such as the use of 75% as the historic nuclear capacity factors, O&M expenses for new plants much lower than existing CT's, and full inclusion of the Salem unit. PECO has a great opportunity to mitigate its stranded costs by reducing O&M expenses, increasing its nuclear output and increasing sales. If the Commission accepts one of the lower market value calculations, it runs a great risk of forcing ratepayers to substantially overcompensate PECO's shareholders for stranded costs.

Q. Does this conclude your testimony?

A. Yes.

PAIEUG STATEMENT NO. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

EXHIBITS

OF

RANDALL J. FALKENBERG

ON BEHALF OF THE

PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

JUNE 1997

QUALIFICATIONS OF RANDALL J. FALKENBERG, VICE PRESIDENT

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

QUALIFICATIONS OF RANDALL J. FALKENBERG, VICE PRESIDENT

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance" December 7, 1995 Issue

Expert Testimony Appearances
of
Randall J. Falkenberg
As of Mid 1997

Date	Case	Jurisdict.	Party	Utility	Subject
3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85	I-840381	PA	Phila. Area Ind. Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation planning economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics of pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power	West Penn Power	Optimal reserve margins,

Expert Testimony Appearances
of
Randall J. Falkenberg
As of Mid 1997

Date	Case	Jurisdict.	Party	Utility	Subject
			Industrial Intervenors		prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7-Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86 613	9437/	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.

Expert Testimony Appearances
of
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As of Mid 1997

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. PowerCorp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA 19th Div I Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization of gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear power plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel Co.	Kentucky Util.	Contract termination cluase and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.

Expert Testimony Appearances
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As of Mid 1997

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in construction delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Sales & weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements, gas and electric CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Methods & Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Demand-side management, load forecasting, and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.

Expert Testimony Appearances
of
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As of Mid 1997

Date	Case	Jurisdict.	Party	Utility	Subject
11/91	10200	TX	Office of Public Utility Counsel	Texas-New Mexico Power Co.	Imprudence disallowance.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, performance incentive factor.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.

**Expert Testimony Appearances
of
Randall J. Falkenberg
As of Mid 1997**

Date	Case	Jurisdict.	Party	Utility	Subject
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder icentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environemental Costs Of electrictricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.

Expert Testimony Appearances
of
Randall J. Falkenberg
As of Mid 1997

Date	Case	Jurisdict.	Party	Utility	Subject
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, modeling Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract

Docket No. R-00973953

Interrogatory PAIEUG-VI-5

PAIEUG-VI-5 Question:

Please verify that General Electric uses the following process to develop heat rates for MAPS:

a. GE develops an estimate for the design heat rate at full load for each generating unit.

b. GE next applied a "rule" to derive the minimum load and energy consumption at minimum load. For example, at GT the rule is that the minimum load is 5% of the full capacity of the unit, and that 25% of the full load heat input of the unit is required to operate the unit at minimum load. For example, assume a CT has a maximum capacity of 20 mW and a full load design heat rate of 10,000 btu/kWh. At full load, the heat input required is 20,000 * 10,000 or 200 MMBtu. At the 1 mW minimum, the unit consumes 50 MMBtu and has an average heat rate of 50,000 Btu/kWh.

c. The incremental heat rate of the unit is then computed by subtracting the minimum load heat required from the full load heat required and dividing that amount by the difference between minimum and maximum capacity. In the above example, the result would be 150 MMBTU/(19 mW) or 7894.7 BTU/kWh.

PAIEUG-VI-5 Answer:

Yes, this is the procedure followed by GE in developing heat rate curves. In the case of a combustion turbine, 5% of full capacity is the rule for minimum load, and fuel consumption at minimum load is 25% of full load fuel consumption. The specific examples of a 20 MW CT having a full load design heat rate of 10,000 Btu/kWh is useful as a numerical example, but is misleading, since small CTs are more likely to have 14,000-15,000 Btu/kWh heat rates and incremental heat rates of 11,000-12,000 Btu/kWh.

Responsible Witness: W. H. Hieronymus

Interrogatory PAIEUG-VI-6

PAIEUG-VI-6 Question:

Assuming that the answer to Q5. above is yes (or approximately yes), then for each type of generating unit modeled in the GE MAPS program provide the "rule" used, (e.g., for GTs the rule is that minimum is 5% of maximum and that heat input required at minimum is 25% of the heat input at maximum capacity output).

PAIEUG-VI-6 Answer:

GE uses the minimum load level and minimum fuel burn assumptions shown in the table below:

Unit Type	Minimum Load Level (% of full load)	Minimum Load Btu (% of full load heat input)
Nuclear	30%	33%
Fossil Steam	25%	28%
Gas Turbines	5%	25%
Combined Cycle	20%	25%

Responsible Witness: W. H. Hieronymus

Docket No. R-00973953

Interrogatory PAIEUG-VI-7

PAIEUG-VI-7 Question:

Provide all supporting documentation regarding the derivation of the figures provided in response to Q6. above.

PAIEUG-VI-7 Answer:

These assumptions are employed by GE in developing regional databases from public domain information. These data represent GE's engineering assessment and there are no supporting documents to back up these assumptions.

Responsible Witness: W. H. Hieronymus

Interrogatory PAIEUG-VI-1

PAIEUG-VI-1 Question:

Please describe the method used by EDS to develop heat rate input data for the PMDAM model. To the extent that the methodology utilizes data derived from an EPRI TAG, provide that source data.

Questions 1-4 relate to information discussed at the meeting on February 20, 1997, between the representative of EDS and Randall J. Falkenberg of J. Kennedy and Associates, Inc.

PAIEUG-VI-1 Answer:

When 1993 FERC Form 1 data is available, EDS develops heat rate input data by using the average Btu per kWh of net generation from Form 1 and then adjusting the Form 1 value by the heat rate profile in EPRI TAG. If FERC Form 1 data is not available, EDS uses heat rate data directly from EPRI TAG. Attachment PAIEUG-VI-1 (a) provides heat rate data from EPRI TAG.

Responsible Witness: J. F. Bustard

%	Full Load	75% Load	50% Load	25% Load
AFBC	0.970884	0.970884	0.970884	0.970884
CCGAS	0.970838	1.018226	1.144593	1.532199
CCOIL	0.970826	1.019243	1.132218	1.533209
CT<60	0.840426	0.912234	1.043218	1.494681
CT>60	0.84022	0.911846	1.0427	1.49449
CTOIL	0.840228	0.911555	1.042796	1.494294
FLAT	1	1	1	1
IG	0.97103	1.037554	1.204938	1.69206
PULV	0.971489	1.00832	1.083705	1.380276
RDF	0.970874	0.970874	0.970874	0.970874

%	Full Load	75% Load	50% Load	25% Load
AFBC	9670	9670	9670	9670
CCGAS	7990	8380	9420	12610
CCOIL	7820	8210	9120	12350
CT<60	12840	13720	15690	22480
CT>60	12200	13240	15140	21700
CTOIL	11780	12780	14620	20950
FLAT	10000	10000	10000	10000
IG	9050	9670	11230	15770
PULV	9575	9938	10681	13604
RDF	15000	15000	15000	15000

SERC

CA	GAS	CCGAS
CA	NG	CCGAS
CC	NG	CCGAS
CG	BIO	RDF
CG	COL	IG
CG	NG	CCGAS
CG	WH	CCGAS
CS	NG	CCGAS
CT	FO2	CTOIL
CT	FO6	CTOIL
CT	GAS	SIZE
CT	NG	SIZE
CW	NG	SIZE
CW	WH	RDF
GT	FO2	CTOIL
GT	GAS	SIZE
GT	LPG	SIZE
GT	NG	SIZE
HY	WAT	NONE
IC	FO2	SIZE
IC	GAS	SIZE
IC	NG	SIZE
IG	BIT	IG
NA	NA	NONE
NB	UR	FLAT
NP	UR	FLAT
OT	BIO	RDF
OT	MSW	RDF
OT	NG	CCGAS
OT	REF	RDF
PS	WAT	NONE
ST	BIT	PULV
ST	COL	PULV
ST	FO2	FLAT
ST	FO6	FLAT
ST	GAS	FLAT
ST	NG	FLAT
ST	REF	FLAT
ST	SUB	PULV
ST	WD	FLAT
UN	UN	FLAT

MAAC

AB	COL	AFBC
AB	WC	AFBC
CA	FO2	CCOIL
CH	ANT	IG
CH	BIT	IG
CT	NG	SIZE
CW	WH	RDF
CW	ZZF	RDF
GT	FO2	CTOIL
GT	KER	CTOIL
GT	NA	SIZE
GT	NG	SIZE
GT	OT	SIZE
HY	WAT	NONE
IC	FO2	SIZE
JE	NG	SIZE
NA	COL	PULV
NA	NA	NONE
NB	UR	FLAT
NP	UR	FLAT
OT	NG	SIZE
PS	WAT	NONE
ST	ANT	PULV
ST	BFG	FLAT
ST	BIT	PULV
ST	COG	FLAT
ST	COL	PULV
ST	FO4	FLAT
ST	FO6	FLAT
ST	NA	FLAT
ST	NG	FLAT
ST	OT	FLAT
ST	REF	FLAT
ST	ZZF	FLAT

ECAR

CA	NG	CCGAS
CS	NG	CCGAS
CT	FO2	CTOIL
CT	NG	SIZE
CW	WH	RDF
GT	BIO	RDF
GT	FO2	CTOIL
GT	GAS	SIZE
GT	NA	SIZE
GT	NG	SIZE
HY	WAT	NONE
IC	FO2	SIZE
IC	NG	SIZE
IG	SNG	SIZE
JE	NG	SIZE
NA	COL	PULV
NA	GAS	SIZE
NA	NA	NONE
NB	UR	FLAT
NP	UR	FLAT
PS	WAT	NONE
ST	COL	PULV
ST	FO2	FLAT
ST	FO6	FLAT
ST	NA	FLAT
ST	NG	FLAT
ST	OT	FLAT
ST	REF	FLAT
ST	WC	FLAT
ST	WD	FLAT

TUVGUYS

AB	WC	AFBC
CA	NG	CCGAS
CC	NG	CCGAS
CT	FO2	CTOIL
CT	GAS	SIZE
CT	NG	SIZE
GT	FO2	CTOIL
GT	GAS	SIZE
GT	NG	SIZE
HY	WAT	NONE
IC	NG	SIZE
IG	BIT	PULV
IG	SNG	SIZE
NP	UR	FLAT
OT	NG	SIZE
PS	WAT	NONE
ST	BIT	PULV
ST	COL	PULV
ST	REF	FLAT
ST	WD	FLAT

Exhibit No. ___(RJF-3), Page 2 of 2
Docket No. R-0097[illegible]

tag 5/22/97

PAIEUG-I-12 Question:

Does PECO agree or disagree that an independent power producer in a competitive market would have a higher cost of capital and/or a higher required equity return than PECO's current cost of capital and return on equity?

PAIEUG-I-12 Answer:

PECO cannot agree or disagree that an independent power producer in a competitive market would have a higher cost of capital and/or a higher required equity return than PECO's current cost of capital and return on equity. In order to answer the question, one needs to know how the hypothetical independent power producer is financed in terms of the relative employment of debt and equity. For example, if it is assumed the independent power producer was financed with 100% equity and the cost rate was assumed to be as low as 11%, and the effective income tax rate was 40%, such hypothetical independent power producer would have a revenue cost of capital, or a before-income tax overall cost of capital of 18.33% An 18.33% before-income tax overall cost of capital is clearly higher than PECO's existing cost of capital or its marginal cost of capital.

If, on the other hand, the hypothetical independent power producer was financed with 80% debt and 20% common equity, depending upon the cost rates related to each, the possibility exists that the before-income tax overall rate of return may be lower than PECO's before-income tax overall cost of capital.

Responsible Witness: J. F. Brennan

Docket No. R-00973953

Interrogatory PAIEUG-VI-8

PAIEUG-VI-8 Question:

Verify that as PHB has applied MAPS in this proceeding the Monte Carlo method was used, but that only one simulation was actually applied. Verify that this means that for each generating unit modeled one set of forced outages was applied for each year modeled.

PAIEUG-VI-8 Answer:

The Monte Carlo method was used. MAPS randomly selects a set of weeks for each generating unit to represent that unit's forced outages over the year.[1] This was done independently for each of approximately 1000 generating unit. The result is that for each of 4380 time periods (MAPS was run in mode in which each time period represents two hours), the forced outage status of each unit is selected at random.

Responsible Witness: W. H. Hieronymus

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[1] If the forced outage rate corresponds to a non-integral number of weeks, the unit will be derated for the last week of outage. For example, if the forced outage rate corresponds to 2.5 weeks of forced outages, then MAPS will derate the unit by 50% for the last week selected.

Exhibit No.___(RJF- 6)
Results of Monte Carlo Simulation
PJM All Hours Market Price - 1999
\$/mWh

Case	Simulation	\$/mWh	% Average
1	A	19.6	97.9
2	B	19.2	95.8
3	C	18.7	93.2
4	D	20.2	101.0
5	E	20.0	99.9
6	F	20.1	100.2
7	G	18.7	93.4
8	H	21.7	108.3
9	I	21.8	108.6
10	J	20.5	102.2
11	K	20.9	104.2
12	L	19.1	95.2

Sample Mean (One Sim Cases)	20.0	Avg of 12 Cases \$20.0/mWh
Std. Deviation One Simulation	1.0	
Std. Dev. Sample Size 1	1.0	5.0%
Std. Dev. Sample Size 12	0.3	1.52%
Std. Dev. Sample Size 100	0.1	0.51%

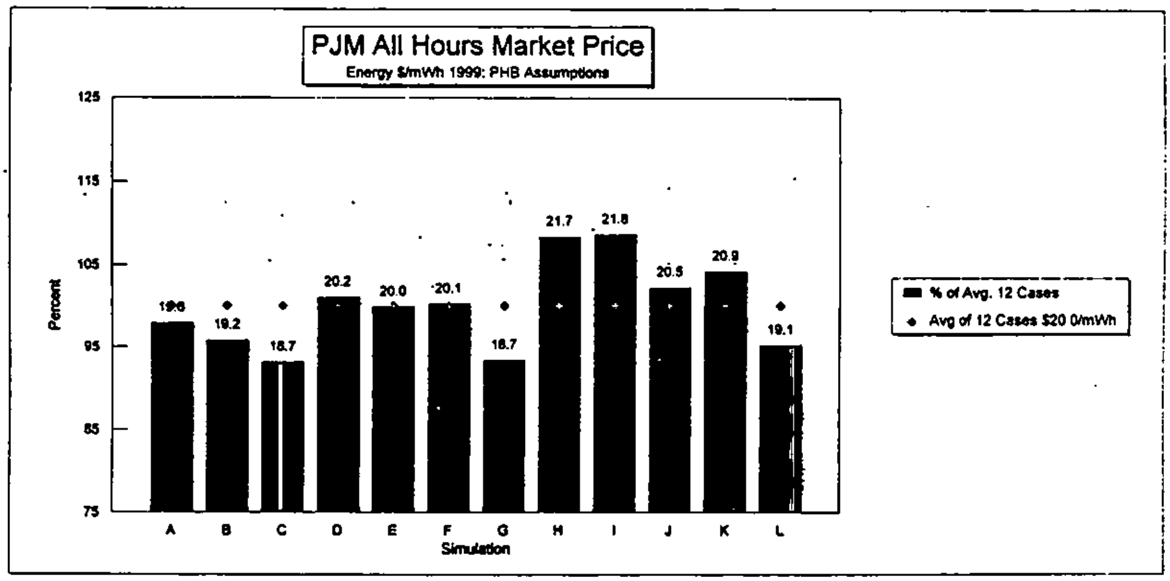

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Exhibit No.___(RJF-7)

PRODUCTION COST MODEL STUDIES AND BENCHMARKS TO UTILITY COMPANY MODELS USED IN REGULATORY PROCEEDINGS

Year	Company	Docket No.	Utility Co. Model	Application
1984	Louisville Gas & Electric	KPSC-8924	EBASCO Prod. Cost Model	Production Cost
1984	Florida Power Corp.	FPSC-830470 EI	EMA PROMOD III	Production Cost
1984	Connecticut Light & Power	COPUC-840713	NU Deterministic	Production Cost
1985	Monongahela Power Co.	WVPSC-84-768-E42T	NA	Reliability
1985	Louisville Gas & Electric	KPSC-9243	EPRI EGEAS	Production Cost
1985	Cincinnati Gas & Electric	KPSC-9299	NA	Reliability
1986	Georgia Power Company	GPSC-3554-U	EPRI UPM	Production Cost
1986	Big Rivers Electric Corp.	KPSC-9437,9613	EMA PROMOD III, BREC Model	Reliability
1987	Monongahela Power Co.	WVPS-86-524-E-SC	EMA PROMOD III	Production Cost & Reliability
1987	West Penn Power Co.	PENN. PUC R850220	EMA PROMOD III	Production Cost & Reliability
1987	Georgia Power Company	GPSC-3673-U	GPC MODEL	Production Cost
1988	Louisville Gas & Electric	KPSC-9984	EPRI EGEAS	Production Cost & Reliability
1988	Cleveland Electric	PUCO-88-170 EL AIR	Centerior Model	Reliability
1988	Toledo Edison	PUCO-88-171 EL AIR	Centerior Model	Reliability
1989	West Penn Power Co.	P-870216/283 /284/286	PROMOD III, APS Historic Data	Production Cost & Reliability
1989	Georgia Power Company	GPSC 3840-U	EPRI UPM	Production Cost
1990	Ohio Edison Company	89-1001-EL-AIR	OES	Reliability
1990	New Orleans Public Service, Inc.	City Council Hearing	n/a	Reliability
1992	GSU/Entergy	U-19904	EMA PROMOD III	Production Cost
1992	Potomac Edison	8179	n/a	Production Cost
1995	Pennsylvania	I-940032	n/a	Market Price Simulation
1997	PECO Energy	R-00973593	EDS-PMDAM, ICF-IPM, GE- MAPS	PJM Pool Market Prices

Exhibit No.____(RJF- 8)

Comparison of Market Price Model Results
K&A Model vs. MAPS,IPM, PMDAM

	PHB Assumptions				ICF Assumptions				EDS Assumptions							
	Market Energy				Market Energy				Market Energy				Cap. & Energy			
Year	MAPS	K&A	$/mWh	% Diff.	IPM	K&A	$/mWh	% Diff.	PMDM	K&A	$/mWh	% Diff.	PMDM	K&A	$/mWh	% Diff.
1999	20.50	23.04	2.54	12.37%	22.18	24.34	2.16	9.7%	22.08	22.86	0.77	3.51%	25.72	26.49	0.77	3.01%
2000					23.86	25.77	1.91	8.0%	23.50	24.25	0.75	3.19%	28.23	28.98	0.75	2.65%
2001					24.59	25.73	1.14	4.6%	25.08	25.11	0.03	0.14%	31.94	31.98	0.03	0.11%
2002					25.59	26.73	1.14	4.4%	26.07	26.46	0.39	1.49%	33.30	33.49	0.18	0.55%
2003					26.44	27.23	0.79	3.0%	27.33	27.66	0.33	1.20%	34.90	34.85	-0.04	-0.13%
2004	28.00	28.12	0.12	0.43%	27.51	27.60	0.09	0.3%	28.53	28.74	0.21	0.75%	36.40	36.16	-0.24	-0.65%
2005					28.66	28.25	-0.41	-1.4%	29.45	29.90	0.45	1.52%	37.56	37.46	-0.10	-0.26%
2006					30.04	29.73	-0.31	-1.0%	30.55	31.52	0.97	3.18%	38.76	38.88	0.11	0.29%
2007					31.28	30.68	-0.60	-1.9%	31.93	32.61	0.68	2.11%	40.29	40.47	0.18	0.44%
2008					32.77	31.66	-1.11	-3.4%	33.86	33.75	-0.11	-0.33%	42.14	41.99	-0.15	-0.36%
2009	36.15	35.34	-0.81	-2.23%	33.91	33.35	-0.56	-1.7%	34.88	35.70	0.82	2.34%	43.67	43.69	0.01	0.03%
2010					35.29	34.52	-0.77	-2.2%	36.66	37.05	0.39	1.06%	45.70	45.47	-0.23	-0.51%
2011					36.43	35.77	-0.66	-1.8%	37.84	38.25	0.42	1.10%	47.26	47.18	-0.08	-0.18%
2012					37.80	37.11	-0.69	-1.8%	39.96	39.55	-0.41	-1.03%	49.00	48.99	-0.01	-0.03%
2013					39.24	39.20	-0.04	-0.1%	41.07	41.74	0.66	1.62%	50.69	50.75	0.06	0.12%
2014					40.69	40.71	0.02	0.1%	42.81	43.23	0.42	0.97%	52.93	52.73	-0.20	-0.38%
Average	28.22	28.83	0.62	2.18%	31.02	31.15	0.13	0.42%	31.98	32.40	0.42	1.32%	39.91	39.97	0.07	0.16%

Exhibit No. ___(RJF-9a)
TOTAL STRANDED COST CALCULATION

Net Present Value of Contribution Margins	$3,499,835
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	$1,000,500
Total Adjusted NPV	$4,811,327
Book Value	$6,688,384
Stranded Generation Cost	$1,877,057

Scenario: EIA FUEL PRICE Escalation

Exhibit No.___(RJF-9b)

CALCULATION OF NET PRESENT VALUE OF CONTRIBUTION MARGINS

		=============Capacity============				Capacity	Capacity	Energy	PSH								Net
	Year	Large Units	CT's	PSH	Total	Charges	Revenue	Margins	Magins	Total Costs	O&M	Cap. Add	A&G	Other Tax	Decomm.	Life Ext.	Margin
	1999	7462	835	880	9177	24.17	$221,826	$687,118	$8,891	$833,135	$505,885	$95,311	$49,177	$87,573	$26,425	$68,764	$84,700
	2000	7462	835	880	9177	30.82	$282,852	$769,598	$11,167	$781,284	$519,201	$97,684	$50,401	$87,573	$26,425	$0	$282,333
	2001	7462	835	880	9177	46.50	$426,695	$774,134	$11,364	$800,265	$533,739	$100,615	$51,913	$87,573	$26,425	$0	$411,928
	2002	7462	835	880	9177	49.05	$450,097	$799,620	$11,839	$819,774	$548,672	$103,633	$53,471	$87,573	$26,425	$0	$441,782
	2003	7462	835	880	9177	53.43	$490,304	$813,077	$12,807	$936,032	$571,987	$106,742	$55,075	$87,573	$26,425	$88,230	$380,157
	2004	7462	835	880	9177	58.16	$533,751	$818,383	$12,021	$902,147	$589,582	$109,944	$56,727	$87,573	$26,425	$31,895	$462,008
Disc. Rate	2005	7462	835	880	9177	59.97	$550,350	$853,605	$13,367	$894,221	$608,551	$113,243	$58,429	$87,573	$26,425	$0	$523,102
7.60%	2006	7462	835	880	9177	61.18	$561,410	$893,432	$12,403	$1,015,635	$627,369	$117,082	$60,410	$87,573	$26,425	$96,777	$451,610
	2007	7462	835	880	9177	61.34	$562,906	$936,495	$13,919	$946,028	$648,522	$121,051	$62,458	$87,573	$26,425	$0	$587,292
Tax Rate	2008	7462	835	880	9177	64.36	$590,647	$962,632	$11,524	$973,623	$669,896	$125,154	$64,575	$87,573	$26,425	$0	$591,180
41.49%	2009	7462	835	880	9177	64.59	$592,708	$1,010,213	$13,739	$1,002,521	$692,362	$129,397	$66,764	$87,573	$26,425	$0	$614,139
	2010	7462	835	880	9177	67.43	$618,846	$1,040,110	$13,658	$1,185,489	$710,916	$133,784	$69,027	$87,573	$26,425	$157,764	$487,125
	2011	7183	835	880	8898	68.51	$609,585	$1,066,174	$14,245	$1,022,564	$709,991	$135,798	$67,571	$82,779	$26,425	$0	$667,441
	2012	7183	835	880	8898	69.75	$620,631	$1,119,973	$15,745	$1,057,885	$738,073	$140,632	$69,977	$82,779	$26,425	$0	$698,463
Post 2014	2013	7183	835	880	8898	73.64	$655,253	$1,158,214	$13,542	$1,087,820	$763,858	$145,639	$72,468	$82,779	$23,077	$0	$739,189
Inflation	2014	6719	835	880	8434	77.28	$651,808	$1,100,281	$14,326	$1,169,285	$790,508	$150,824	$75,048	$82,779	$19,251	$50,876	$597,131
3.56%	2015	5638	0	880	6518	80.03	$521,666	$1,000,817	$14,837	$925,033	$669,132	$122,326	$55,360	$58,964	$19,251	$0	$812,287
	2016	5638	0	880	6518	82.88	$540,237	$1,036,448	$15,365	$952,080	$692,369	$126,680	$57,331	$58,964	$16,735	$0	$639,970
	2017	5167	0	880	6047	85.83	$519,042	$974,546	$15,912	$852,499	$597,408	$120,021	$59,372	$58,964	$16,735	$0	$657,000
	2018	5167	0	880	6047	88.89	$537,520	$1,009,241	$16,478	$879,570	$618,091	$124,294	$61,488	$58,964	$16,735	$0	$683,669
	2019	4811	0	880	5691	92.05	$523,884	$985,581	$17,065	$888,270	$625,754	$123,143	$63,675	$58,964	$16,735	$0	$638,259
	2020	4667	0	880	5547	95.33	$528,806	$1,001,032	$17,672	$880,479	$622,587	$124,389	$63,050	$56,378	$14,075	$0	$667,031
	2021	4196	0	880	5076	98.73	$501,132	$922,654	$18,301	$758,983	$507,265	$115,971	$65,294	$56,378	$14,075	$0	$683,104
	2022	3844	0	880	4724	102.24	$482,984	$876,430	$18,953	$736,407	$482,633	$115,702	$67,619	$56,378	$14,075	$0	$641,959
	2023	3844	0	880	4724	105.88	$500,178	$907,632	$19,628	$752,970	$499,231	$119,821	$70,028	$56,378	$7,514	$0	$674,467
	2024	3844	0	880	4724	109.65	$517,984	$939,943	$20,326	$776,917	$516,420	$124,087	$72,519	$56,378	$7,514	$0	$701,338
	2025	2689	0	880	3569	113.55	$405,271	$591,080	$21,050	$488,561	$329,040	$71,852	$44,984	$33,770	$8,916	$0	$528,839
	2026	1627	0	880	2507	117.60	$294,812	$487,882	$21,799	$398,117	$259,004	$65,120	$37,728	$27,349	$8,916	$0	$406,376
	2027	1627	0	880	2507	121.78	$305,307	$505,250	$22,575	$410,707	$267,933	$67,439	$39,071	$27,349	$8,916	$0	$422,426
	2028	1627	0	880	2507	126.12	$316,176	$523,238	$23,379	$423,745	$277,179	$69,839	$40,462	$27,349	$8,916	$0	$439,048
	2029	1627	0	880	2507	130.61	$327,432	$541,866	$24,211	$437,248	$286,755	$72,326	$41,902	$27,349	$8,916	$0	$456,262

NPV of Net Margins After Tax **$3,499,835**

Fuel Cost $ (1000)

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delewar 7	Delewar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2018	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	325748	17	32618	34367	15866	16108	22822	22687	15234	15167	17809	17435	22935	21486	10146	10824	18286	17835	4858	4172	4862
2000	338405	17	32704	34250	15832	16112	22730	22805	15412	15358	18152	17814	24021	22564	10765	11826	21578	19807	5487	4971	5870
2001	340562	17	33073	34637	16112	16294	22980	23074	15610	15567	18524	18200	23648	22187	10884	11657	21314	20851	5508	4878	5742
2002	343230	17	33447	35028	16294	16478	23249	23339	15801	15764	18829	18521	23297	21836	10890	11710	21428	20775	5612	4997	5917
2003	348120	17	33825	35424	16478	16864	23500	23597	15987	15957	19138	18850	26807	21409	10847	11626	21277	20824	5505	4984	5711
2004	354210	17	34207	35825	16864	16853	23783	23868	16174	16148	19578	19336	27430	25837	10268	11334	20733	20085	5458	4861	5572
2005	364511	17	34594	36229	16853	17043	24031	24241	16371	16349	19887	19664	28307	26801	13758	11728	21452	20764	5894	5078	5632
2006	376188	17	35871	37567	17474	17672	24907	25127	17150	17132	20904	20894	30221	28651	10607	11968	21913	21248	5894	5201	5901
2007	383202	17	37194	38952	18118	18324	25828	26058	17971	17958	21965	21787	32217	30577	11094	12441	22773	22087	6169	5535	6156
2008	407874	17	38587	40380	18787	19001	26784	27023	18833	18822	23073	22688	34324	32613	11283	12494	22873	22183	6222	5580	6208
2009	425871	17	39990	41880	19481	19702	28169	28005	19721	19713	24214	24044	36525	34742	11583	12806	23487	22779	6471	5844	6518
2010	428452	17	41465	43428	20200	20429	29208	29042	20744	20655	25303	25108	38633	23868	11798	12897	23638	22944	6550	5872	6413
2011	419807	17	42946	44878	20821	21157	30251	30082	21170	21083	25882	25842	40193	0	12067	13620	24980	24238	6871	6223	7008
2012	442381	17	44479	46582	21068	21813	31331	31181	21606	21521	26557	26433	41580	0	20799	14171	25897	25208	7146	6508	7646
2013	455722	17	46088	48245	22441	22695	32450	32278	22050	21988	27136	27028	42968	0	21582	14487	26600	25856	7245	6610	8014
2014	445290	17	47711	49867	0	23508	33609	33909	22488	22404	27705	27608	44348	0	22322	14860	27270	25184	7475	6730	8175
2015	398272	18	49307	51727	0	0	34820	35129	23290	23204	28686	28584	45920	0	23119	0	28265	26113	0	0	0
2016	412449	18	51150	53568	0	0	36058	36380	24119	24030	29708	29602	47554	0	23942	0	29271	27043	0	0	0
2017	389482	19	52877	55478	0	0	37342	0	24978	24886	30765	30656	49247	0	24795	0	30314	28008	0	0	0
2018	403323	20	54862	57450	0	0	38672	0	25868	25771	31860	31748	51001	0	25678	0	31393	29002	0	0	0
2019	351812	21	56816	59496	0	0	40049	0	26788	26689	0	0	52816	0	26592	0	32510	30035	0	0	0
2020	338796	21	58838	61614	0	0	41475	0	27742	27639	0	0	54696	0	0	0	33667	31104	0	0	0
2021	305836	22	60933	63807	0	0	0	0	28730	28623	0	0	56644	0	0	0	34868	32211	0	0	0
2022	257329	22	63102	66079	0	0	0	0	0	0	0	0	58681	0	0	0	36107	33358	0	0	0
2023	266491	23	65349	68431	0	0	0	0	0	0	0	0	60749	0	0	0	37393	34548	0	0	0
2024	275978	25	67675	70867	0	0	0	0	0	0	0	0	62911	0	0	0	38724	35778	0	0	0
2025	212413	25	70085	0	0	0	0	0	0	0	0	0	65151	0	0	0	40103	37049	0	0	0
2026	72605	26	72579	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	75180	27	75183	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	77867	28	77839	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	80638	29	80609	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fuel Cost $/MWh

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delewar 7	Delewar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2018	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	8.31	0.01	4.48	4.53	5.24	5.30	7.71	7.78	11.91	11.91	14.61	14.60	16.60	16.80	17.55	22.70	24.23	24.80	29.50	33.92	37.40
2000	8.54	0.01	4.46	4.51	5.22	5.28	7.69	7.76	12.04	12.05	14.77	14.77	16.80	16.98	17.74	23.23	24.72	25.10	30.56	35.51	38.87
2001	8.62	0.01	4.51	4.58	5.28	5.34	7.77	7.84	12.18	12.19	14.95	14.94	16.99	17.17	17.83	24.04	25.59	25.88	32.01	36.85	40.44
2002	8.72	0.01	4.58	4.61	5.34	5.40	7.86	7.93	12.33	12.33	15.12	15.12	17.18	17.39	18.15	24.88	26.52	26.88	33.21	38.15	41.98
2003	8.84	0.01	4.62	4.67	5.40	5.46	7.95	8.02	12.47	12.47	15.30	15.30	17.40	17.58	18.36	25.73	27.42	27.43	34.54	39.87	43.83
2004	8.96	0.01	4.67	4.72	5.46	5.52	8.04	8.11	12.63	12.62	15.48	15.48	17.58	17.80	18.57	28.67	28.40	28.78	35.91	41.19	45.30
2005	9.16	0.01	4.72	4.77	5.52	5.59	8.13	8.21	12.77	12.78	15.66	15.87	17.80	18.01	18.80	27.80	29.35	29.78	37.22	43.01	47.33
2006	9.49	0.01	4.90	4.95	5.73	5.79	8.43	8.51	13.36	13.37	16.41	16.40	18.65	18.98	18.72	28.63	30.46	30.83	39.03	44.78	49.58
2007	9.90	0.01	5.06	5.13	5.94	6.01	8.74	8.82	14.01	14.01	17.20	17.18	19.54	19.77	20.02	28.69	31.63	32.06	40.85	46.91	51.30
2008	10.28	0.01	5.26	5.32	6.18	6.23	9.07	9.15	14.68	14.68	18.00	18.01	20.47	20.71	21.61	30.77	32.82	33.31	42.04	49.03	53.52
2009	10.71	0.01	5.46	5.52	6.39	6.46	9.40	9.48	15.36	15.38	18.86	18.87	21.43	21.69	22.62	31.94	34.08	34.87	44.02	50.38	55.71
2010	10.94	0.01	5.66	5.72	6.62	6.70	9.75	9.83	16.12	16.11	19.75	19.77	22.46	22.73	23.69	33.15	35.38	35.85	45.88	52.08	57.77
2011	11.00	0.01	5.88	5.92	6.86	6.93	10.10	10.18	16.44	16.45	20.18	20.18	22.92	0.00	24.18	34.83	37.08	37.64	47.72	54.58	60.41
2012	11.46	0.01	6.07	6.14	7.10	7.18	10.46	10.55	16.77	16.77	20.58	20.57	23.40	0.00	24.70	36.52	38.92	38.42	49.28	57.08	62.87
2013	11.83	0.01	6.29	6.36	7.36	7.44	10.83	10.93	17.12	17.12	21.00	21.00	23.87	0.00	25.18	38.25	40.60	41.37	51.38	58.02	64.83
2014	12.35	0.01	6.51	6.58	0.00	7.70	11.22	11.32	17.47	17.48	21.43	21.44	24.35	0.00	25.72	40.18	42.74	43.35	53.01	61.18	67.01
2015	12.57	0.01	6.74	6.81	0.00	0.00	11.62	11.73	18.10	18.10	22.18	22.19	25.22	0.00	26.83	0.00	44.38	44.84	0.00	0.00	0.00
2016	13.02	0.01	6.98	7.08	0.00	0.00	12.04	12.14	18.74	18.74	22.98	22.98	26.11	0.00	27.58	0.00	45.88	46.55	0.00	0.00	0.00
2017	13.58	0.01	7.23	7.31	0.00	0.00	12.48	0.00	19.41	19.41	23.78	23.80	27.04	0.00	28.57	0.00	47.51	48.20	0.00	0.00	0.00
2018	14.08	0.01	7.49	7.57	0.00	0.00	12.91	0.00	20.10	20.10	24.64	24.65	28.01	0.00	29.58	0.00	48.21	49.82	0.00	0.00	0.00
2019	13.48	0.01	7.75	7.84	0.00	0.00	13.37	0.00	20.81	20.82	0.00	0.00	29.00	0.00	30.64	0.00	50.86	51.79	0.00	0.00	0.00
2020	13.34	0.01	8.03	8.12	0.00	0.00	13.84	0.00	21.56	21.56	0.00	0.00	30.04	0.00	0.00	0.00	52.77	53.54	0.00	0.00	0.00
2021	13.75	0.01	8.32	8.41	0.00	0.00	0.00	0.00	22.32	22.33	0.00	0.00	31.11	0.00	0.00	0.00	54.65	55.44	0.00	0.00	0.00
2022	13.08	0.01	8.61	8.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.21	0.00	0.00	0.00	56.50	57.41	0.00	0.00	0.00
2023	13.54	0.01	8.92	9.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.38	0.00	0.00	0.00	58.61	59.46	0.00	0.00	0.00
2024	14.03	0.01	9.24	9.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.55	0.00	0.00	0.00	60.78	61.58	0.00	0.00	0.00
2025	17.58	0.01	9.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.78	0.00	0.00	0.00	62.88	63.77	0.00	0.00	0.00
2026	9.03	0.02	9.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	8.31	0.02	10.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	9.61	0.02	10.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	9.87	0.02	11.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Market Energy Prices $/MWh

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	25.84	23.95	24.78	24.28	24.28	24.29	24.39	24.37	24.24	24.27	24.84	25.03	28.72	29.08	31.00	38.95	40.43	41.28	48.10	53.71	58.58
2000	25.82	25.70	26.17	26.17	26.10	26.19	26.31	26.27	26.10	26.15	26.68	26.81	30.90	31.25	33.28	41.89	42.41	44.27	52.01	56.18	63.03
2001	26.28	26.04	26.41	26.40	26.41	26.41	26.53	26.48	26.33	26.37	26.85	27.03	31.50	31.88	33.53	43.28	43.75	44.83	54.52	59.80	65.32
2002	26.81	26.87	27.08	27.09	27.10	27.10	27.23	27.20	26.99	27.04	27.48	27.68	32.78	33.22	34.71	45.54	46.18	47.03	57.34	63.08	68.70
2003	27.40	27.10	27.53	27.53	27.54	27.54	27.68	27.64	27.42	27.44	27.85	28.03	31.39	34.21	35.81	47.38	48.02	48.00	58.77	66.11	73.12
2004	27.80	27.34	27.77	27.77	27.78	27.78	27.92	27.83	27.68	27.70	27.96	28.11	31.46	31.74	36.81	49.32	49.85	50.89	62.27	68.47	75.81
2005	29.22	28.28	28.71	28.70	28.72	28.72	28.95	28.88	28.61	28.60	28.87	29.02	32.31	32.58	33.48	51.42	51.98	53.05	64.73	71.73	80.38
2006	30.07	29.52	29.89	29.89	30.00	30.00	30.18	30.16	29.88	29.88	30.11	30.21	33.44	33.68	40.41	54.28	54.93	56.07	68.81	75.88	85.31
2007	31.63	30.91	31.38	31.37	31.38	31.38	31.54	31.54	31.25	31.28	31.48	31.58	34.68	34.93	42.24	56.68	57.41	58.53	72.34	79.84	88.83
2008	32.58	31.82	32.40	32.39	32.41	32.41	32.58	32.58	32.27	32.28	32.44	32.58	35.48	35.68	44.07	59.12	60.94	61.21	74.75	83.81	93.31
2009	33.60	33.35	33.88	33.88	33.89	33.89	34.01	34.07	33.76	33.75	33.89	34.01	36.80	37.02	46.54	62.47	63.38	64.70	79.30	87.18	98.58
2010	34.68	34.47	35.02	35.02	35.03	35.03	35.15	35.21	34.95	34.89	35.08	35.18	37.74	48.18	48.58	65.31	66.28	67.58	82.98	91.88	104.16
2011	36.48	36.02	36.57	36.58	36.58	36.58	36.69	36.78	36.47	36.44	36.53	36.61	39.23	0.00	50.78	68.48	69.31	70.76	87.15	95.60	107.93
2012	37.73	37.58	38.18	38.17	38.18	38.19	38.32	38.39	38.08	38.02	38.15	38.19	40.82	0.00	41.87	72.34	73.28	74.88	81.54	101.58	111.87
2013	39.07	38.82	39.48	39.45	39.47	39.47	39.81	39.88	39.36	39.31	39.40	39.48	41.97	0.00	42.77	75.53	78.58	78.10	98.18	105.80	114.68
2014	40.88	40.20	40.86	40.85	0.00	40.87	41.01	41.01	40.78	40.72	40.78	40.85	43.26	0.00	44.07	78.10	80.03	83.81	99.35	110.58	118.82
2015	41.48	41.61	42.31	42.31	0.00	0.00	42.47	42.47	42.22	42.17	42.23	42.30	44.79	0.00	45.63	0.00	82.98	86.89	0.00	0.00	0.00
2016	42.97	43.08	43.82	43.82	0.00	0.00	43.98	43.88	43.72	43.67	43.73	43.80	46.38	0.00	47.28	0.00	85.91	89.77	0.00	0.00	0.00
2017	44.85	44.83	45.38	45.38	0.00	0.00	45.55	0.00	45.27	45.22	45.28	45.38	48.04	0.00	48.94	0.00	88.97	92.97	0.00	0.00	0.00
2018	46.24	46.22	46.88	46.89	0.00	0.00	47.17	0.00	46.89	46.83	46.80	46.98	49.75	0.00	50.68	0.00	92.14	96.28	0.00	0.00	0.00
2019	48.04	47.86	48.07	48.67	0.00	0.00	48.85	0.00	48.58	48.50	0.00	0.00	51.52	0.00	52.48	0.00	95.42	99.71	0.00	0.00	0.00
2020	49.88	49.57	50.40	50.40	0.00	0.00	50.58	0.00	50.28	50.23	0.00	0.00	53.35	0.00	0.00	0.00	98.82	103.28	0.00	0.00	0.00
2021	51.71	51.33	52.18	52.18	0.00	0.00	0.00	0.00	52.07	52.02	0.00	0.00	55.25	0.00	0.00	0.00	102.33	106.93	0.00	0.00	0.00
2022	53.85	53.18	54.05	54.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.22	0.00	0.00	0.00	105.98	110.74	0.00	0.00	0.00
2023	55.77	55.05	55.87	55.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.25	0.00	0.00	0.00	109.75	114.88	0.00	0.00	0.00
2024	57.75	57.01	57.87	57.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.38	0.00	0.00	0.00	113.86	118.76	0.00	0.00	0.00
2025	61.06	59.04	60.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.55	0.00	0.00	0.00	117.70	122.89	0.00	0.00	0.00
2026	58.98	61.14	62.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	61.08	63.32	64.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	63.25	65.57	66.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	65.50	67.81	69.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Market Energy Revenues ($1000)

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	1012808	41118	177819	184302	74108	74108	72175	71069	31003	30919	30275	29882	38687	37212	17820	18228	30488	29507	8080	6808	7818
2000	1108003	44284	191784	198843	78872	78872	77778	77246	33408	33337	32820	32452	44188	41534	20222	21322	37020	34829	8873	8145	8518
2001	1114898	44707	193488	200430	80581	80581	78454	77847	33734	33678	33262	32918	43843	41182	20350	20878	38447	35482	9378	7953	8275
2002	1142850	45798	198518	205837	82685	82685	80527	80011	34808	34558	34209	33880	44423	41727	20828	21451	37313	38355	9690	8763	8687
2003	1161187	46531	201718	208955	84018	84019	81785	81265	35158	35118	34842	34533	48375	41831	20768	21422	37265	38310	9683	8264	9505
2004	1172583	46951	203502	210802	84782	84782	82507	82482	35484	35427	35373	35111	49047	46250	20358	20883	36480	35518	8465	8078	9300
2005	1218118	48565	210352	217888	87614	87614	85261	85250	38673	38643	36659	36415	51371	48489	24504	21852	37988	37028	8803	8464	9565
2006	1288830	50881	219788	227850	91538	81538	89082	89074	38301	38778	38358	38127	54173	51158	21748	22887	38495	38518	10381	8828	10152
2007	1328897	53078	228812	238180	95782	95782	93168	93158	40088	40089	40210	39991	57183	54038	22724	23748	41333	40324	10824	9388	10871
2008	1370808	54807	237378	245893	98871	98871	96185	96182	41403	41388	41582	41378	59469	56218	23003	24001	41778	40784	11083	9531	10824
2009	1435884	57254	248288	257178	103408	103408	101889	100598	43277	43263	43520	43332	62710	59305	23827	25050	43857	42838	11870	10104	11531
2010	1468582	59185	258807	265813	108881	108881	105308	103985	44977	44724	44908	44892	65246	48504	24182	25407	44285	43258	11888	10290	11582
2011	1485781	61847	267925	277538	111595	111595	108934	108552	46872	46718	47087	46930	68814	0	25330	26788	46844	45567	12549	10898	12520
2012	1582354	64495	278738	288775	118518	118518	114812	113401	49042	48782	49210	49068	72538	0	35082	28088	48953	47854	13274	11581	13648
2013	1613836	66858	288111	298483	120418	120419	118857	117208	50891	50429	50907	50781	75554	0	36815	28825	49833	48812	13563	11850	14220
2014	1545571	68024	299340	310088		124684	122857	122856	52462	52108	52725	52614	78771	0	38250	29288	51061	48578	14008	12182	14618
2015	1388088	71450	310014	321187	0	0	127248	127248	54332	54058	54588	54477	81563	0	39608	0	82828	50388	0	0	0
2016	1448887	73894	321048	332831	0	0	131778	131778	56208	55984	56542	56417	84468	0	41018	0	84813	82158	0	0	0
2017	1384008	78828	332480	344473	0	0	138489	0	58268	57877	58558	58425	87474	0	42478	0	86784	84015	0	0	0
2018	1412584	78337	344315	358735	0	0	141327	0	60343	60041	60640	60505	90588	0	43991	0	58784	55638	0	0	0
2019	1337393	82181	356573	368435	0	0	146358	0	62491	62178	0	0	93813	0	45557	0	80077	57830	0	0	0
2020	1337828	85187	369287	382587	0	0	151570	0	64715	64391	0	0	97154	0	0	0	63045	59982	0	0	0
2021	1226490	88137	382413	398208	0	0	0	0	67019	66584	0	0	100812	0	0	0	65289	62128	0	0	0
2022	1133758	91274	396027	410312	0	0	0	0	0	0	0	0	104184	0	0	0	67813	64338	0	0	0
2023	1174123	94524	410125	424820	0	0	0	0	0	0	0	0	107803	0	0	0	70021	66830	0	0	0
2024	1215821	97888	424728	440047	0	0	0	0	0	0	0	0	111744	0	0	0	72513	69002	0	0	0
2025	803493	101373	439848	0	0	0	0	0	0	0	0	0	115722	0	0	0	75094	71458	0	0	0
2026	560487	104882	455505	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	580440	108720	471720	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	601105	112581	488514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	622504	116598	505905	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Energy Margins ($1000)

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 3	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddyste 2	Eddyste 1	Cromby 1	Cromby 2	Eddyste 3	Eddyste 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	687118	41101	145103	149935	58120	57840	49353	48782	15769	15752	12468	12447	18752	15728	7774	7604	12220	11962	3124	2434	2754
2000	769590	44247	159080	164393	63940	63760	55046	54441	17994	17979	14658	14638	20187	18970	9437	9496	15442	15122	3906	3174	3640
2001	774134	44680	160415	165793	64479	64297	55464	54873	18124	18111	14738	14718	20195	19005	9486	9319	15133	14831	3872	3078	3533
2002	798820	45782	165080	170808	66391	66207	57278	56672	18805	18794	15380	15359	21126	19891	9938	9741	15884	15580	4078	3208	3770
2003	813077	46514	167894	173531	67541	67355	58295	57688	19171	19161	15703	15683	21568	20222	10121	9704	15988	15686	4088	3280	3794
2004	810383	46934	169295	174977	68066	67909	58744	58524	19290	19281	15705	15775	21817	20313	10090	9829	15727	15433	4006	3218	3728
2005	853605	48548	175758	181089	70761	70571	61230	61009	20302	20294	16772	16751	23064	21698	10745	10124	16546	16242	4209	3389	3933
2006	893432	50864	183895	190083	74082	73864	64175	63947	21151	21144	17454	17433	23952	22507	11133	10718	17583	17271	4497	3647	4251
2007	938495	53050	192718	198208	77643	77438	67338	67101	22118	22111	18245	18224	24966	23459	11830	11307	18580	18237	4755	3863	4519
2008	962632	54790	198811	205503	80084	79870	69411	69169	22570	22566	18509	18490	25144	23603	11720	11507	18905	18581	4841	3942	4816
2009	1010213	57237	208279	215298	83927	83706	73720	72593	23558	23550	19306	19288	26185	24583	12244	12244	20190	19857	5198	4260	5013
2010	1040110	59168	215142	222387	86681	86452	76101	74943	24233	24060	19603	19588	26413	24638	12388	12510	20849	20314	5318	4368	5149
2011	1086174	61030	224879	232580	90674	90438	79683	78470	25802	25635	21105	21088	28821	0	13263	13146	21884	21328	5878	4675	5512
2012	1118973	64478	235280	243183	94848	94803	83481	82240	27436	27261	22653	22636	30959	0	14283	13805	22956	22588	6128	5073	6002
2013	1158214	66642	243045	251238	97978	97724	86207	84930	28641	28463	23771	23755	32586	0	15053	14128	23333	22958	6318	5240	6206
2014	1100281	69007	251838	260121	0	101178	89248	88947	29974	29784	25020	25005	34422	0	15928	14406	23791	23392	6533	5432	6443
2015	1000817	71432	260817	269470	0	0	92428	92119	31042	30855	25913	25893	35643	0	16489	0	24683	24253	0	0	0
2016	1036440	73978	269893	279083	0	0	95720	95398	32147	31954	26834	26815	36914	0	17076	0	25542	25118	0	0	0
2017	874540	76800	279503	288887	0	0	99127	0	33269	33091	27791	27769	38227	0	17684	0	26450	26009	0	0	0
2018	1009241	78337	289453	299285	0	0	102655	0	34475	34270	28780	28759	39587	0	18313	0	27391	26938	0	0	0
2019	985581	82160	299757	309938	0	0	106309	0	35703	35489	0	0	40997	0	18965	0	28367	27895	0	0	0
2020	1001032	85066	310429	320973	0	0	110095	0	36973	36752	0	0	42458	0	0	0	29378	28888	0	0	0
2021	822654	88115	321480	332401	0	0	0	0	38289	38061	0	0	43968	0	0	0	30423	29817	0	0	0
2022	876430	91252	332925	344233	0	0	0	0	0	0	0	0	45533	0	0	0	31506	30861	0	0	0
2023	907832	94501	344770	356480	0	0	0	0	0	0	0	0	47154	0	0	0	32628	32084	0	0	0
2024	939943	97864	357051	368180	0	0	0	0	0	0	0	0	48833	0	0	0	33789	33228	0	0	0
2025	591080	101348	369761	0	0	0	0	0	0	0	0	0	50571	0	0	0	34991	34409	0	0	0
2026	487882	104958	382928	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	505250	108693	396557	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	523238	112563	410675	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	541866	116570	425286	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Unit Capacity Factors

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddyste 2	Eddyste 1	Cromby 1	Cromby 2	Eddyste 3	Eddyste 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.58	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	59.97	38.28	75.01	75.03	75.06	75.06	71.72	71.28	82.96	82.03	78.18	76.57	52.24	52.33	45.82	26.58	22.65	21.54	15.22	11.32	8.94
2000	60.64	38.28	75.01	75.03	75.06	75.08	71.64	71.28	83.02	82.70	78.88	77.34	54.05	54.38	48.20	28.91	20.23	23.70	16.85	12.89	10.38
2001	60.43	38.28	75.01	75.03	75.06	75.06	71.87	71.30	83.00	82.83	79.46	78.11	52.62	52.86	48.12	27.54	25.02	23.88	15.58	12.24	8.77
2002	60.23	38.28	75.01	75.03	75.06	75.06	71.87	71.30	83.15	82.89	79.84	78.56	51.22	51.38	47.56	26.79	24.27	23.22	15.31	12.08	9.70
2003	60.76	38.28	75.01	75.03	75.06	75.06	71.82	71.28	83.15	83.02	80.23	79.01	53.25	49.79	45.88	25.67	23.31	22.28	14.88	11.81	8.94
2004	60.48	38.28	75.01	75.03	75.06	75.06	71.82	71.60	83.09	82.96	81.13	80.10	58.93	58.61	43.84	24.18	21.83	20.97	13.77	10.88	8.48
2005	60.67	38.28	75.01	75.03	75.08	75.06	71.82	71.60	83.15	83.09	81.45	80.49	60.10	60.88	58.03	24.14	21.88	20.97	13.86	10.86	8.18
2006	60.63	38.28	75.01	75.03	75.08	75.08	71.80	71.57	83.15	83.09	81.70	80.93	61.24	62.15	42.65	23.74	21.80	20.84	13.88	10.88	8.18
2007	60.74	38.28	75.01	75.03	75.08	75.06	71.80	71.60	83.22	83.15	81.90	81.28	62.33	63.30	42.65	23.08	21.63	20.70	13.68	10.08	8.25
2008	60.71	38.28	75.01	75.03	75.06	75.06	71.60	71.60	83.22	83.15	82.22	81.51	63.39	64.44	41.38	23.08	20.94	20.01	13.41	10.48	7.86
2009	60.82	38.28	75.01	75.03	75.08	75.06	72.61	71.57	83.15	83.15	82.35	81.70	64.41	65.55	40.58	22.77	20.70	19.80	13.32	10.68	8.05
2010	59.89	38.28	75.01	75.03	75.08	75.06	72.61	71.57	83.48	83.15	82.15	81.45	65.36	42.98	39.48	22.08	20.07	18.23	12.86	10.31	7.83
2011	60.65	38.28	75.01	75.03	75.08	75.06	72.61	71.57	83.54	83.15	82.67	82.22	66.30	0.00	38.58	22.21	20.22	18.35	13.05	10.49	7.96
2012	61.23	38.28	75.01	75.03	75.08	75.08	72.61	71.80	83.54	83.22	82.73	82.41	67.17	0.00	66.75	22.04	20.07	18.28	13.14	10.49	8.39
2013	61.23	38.28	75.01	75.03	75.08	75.06	72.61	71.80	83.54	83.22	82.86	82.54	68.04	0.00	67.88	21.52	18.58	18.70	12.77	10.31	8.53
2014	60.28	38.28	75.01	75.03	0.00	75.06	72.61	72.01	83.48	83.15	82.82	82.60	68.83	0.00	68.81	21.01	19.17	17.48	12.77	10.13	8.39
2015	64.15	38.28	75.01	75.03	0.00	0.00	72.61	72.01	83.48	83.15	82.82	82.60	68.83	0.00	68.61	0.00	19.17	17.45	0.00	0.00	0.00
2016	64.15	38.28	75.01	75.03	0.00	0.00	72.61	72.01	83.48	83.15	82.82	82.60	68.83	0.00	68.61	0.00	19.17	17.45	0.00	0.00	0.00
2017	63.38	38.28	75.01	75.03	0.00	0.00	72.61	0.00	83.48	83.15	82.82	82.60	68.83	0.00	68.81	0.00	19.17	17.45	0.00	0.00	0.00
2018	63.38	38.28	75.01	75.03	0.00	0.00	72.61	0.00	83.48	83.15	82.82	82.60	68.83	0.00	68.61	0.00	19.17	17.45	0.00	0.00	0.00
2019	61.95	38.28	75.01	75.03	0.00	0.00	72.61	0.00	83.48	83.15	0.00	0.00	68.83	0.00	68.61	0.00	19.17	17.45	0.00	0.00	0.00
2020	61.74	38.28	75.01	75.03	0.00	0.00	72.61	0.00	83.48	83.15	0.00	0.00	68.83	0.00	0.00	0.00	19.17	17.45	0.00	0.00	0.00
2021	60.52	38.28	75.01	75.03	0.00	0.00	0.00	0.00	83.48	83.15	0.00	0.00	68.83	0.00	0.00	0.00	19.17	17.45	0.00	0.00	0.00
2022	58.43	38.28	75.01	75.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.83	0.00	0.00	0.00	19.17	17.45	0.00	0.00	0.00
2023	58.43	38.28	75.01	75.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.83	0.00	0.00	0.00	19.17	17.45	0.00	0.00	0.00
2024	58.43	38.28	75.01	75.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.83	0.00	0.00	0.00	19.17	17.45	0.00	0.00	0.00
2025	61.30	38.28	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.83	0.00	0.00	0.00	19.17	17.45	0.00	0.00	0.00
2026	63.40	38.28	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	63.40	38.28	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	63.40	38.28	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	63.40	38.28	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Exhibit No.___(RJF-9c)
PUMPED STORAGE UNITS
ECONOMIC BENEFITS AND OPERATIONS

YEAR	MW	BENEFIT	GEN MWH	CF	PUMPING COST	GEN. VALUE	DAYS	HOURS	LOSS FACTOR
1999	1693	17105550	2129794	14.4	16.94	32.08	234	1258	1.42
2000	1693	21483410	2322796	15.7	17.36	33.9	255	1372	1.42
2001	1693	21863620	2365121	15.9	17.61	34.25	241	1397	1.42
2002	1693	22775790	2204286	14.9	17.97	35.86	230	1302	1.42
2003	1693	24639670	2314331	15.6	18.4	36.77	241	1367	1.42
2004	1342	18332160	1630530	13.9	18.5	37.51	206	1215	1.42
2005	1342	20385230	1735206	14.8	19.16	38.96	220	1293	1.42
2006	1342	18914760	1488278	12.7	19.96	41.05	186	1109	1.42
2007	1342	21225900	1537932	13.1	21.03	43.67	191	1146	1.42
2008	1342	17573490	1295030	11	21.82	44.55	160	965	1.42
2009	1342	20952550	1426546	12.1	22.89	47.19	177	1063	1.42
2010	1342	20828680	1337974	11.4	23.96	49.59	162	997	1.42
2011	1342	21723840	1297714	11	24.89	52.09	161	967	1.42
2012	1342	24011270	1344684	11.4	25.82	54.52	165	1002	1.42
2013	1342	20651490	1223904	10.4	26.55	54.57	150	912	1.42
2014	1342	21847880	1248060	10.6	27.67	56.79	153	930	1.42

Scenario: **EIA FUEL PRICE Escalation**

Exhibit No___(RJF-9d)

Large Units
Capacity mW

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2000	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2001	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2002	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2003	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2004	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2005	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2006	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2007	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2008	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2009	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2010	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2011	7183	512	1115	1155	464	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2012	7183	512	1115	1155	464	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2013	7183	512	1115	1155	464	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2014	6719	512	1115	1155	0	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2015	5638	512	1115	1155	0	0	471	471	176	176	178	178	302	0	144	0	380	380	0	0	0
2016	5638	512	1115	1155	0	0	471	471	176	176	178	178	302	0	144	0	380	380	0	0	0
2017	5167	512	1115	1155	0	0	471	0	176	176	178	178	302	0	144	0	380	380	0	0	0
2018	5167	512	1115	1155	0	0	471	0	176	176	178	178	302	0	144	0	380	380	0	0	0
2019	4811	512	1115	1155	0	0	471	0	176	176	0	0	302	0	144	0	380	380	0	0	0
2020	4667	512	1115	1155	0	0	471	0	176	176	0	0	302	0	0	0	380	380	0	0	0
2021	4196	512	1115	1155	0	0	0	0	176	176	0	0	302	0	0	0	380	380	0	0	0
2022	3844	512	1115	1155	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2023	3844	512	1115	1155	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2024	3844	512	1115	1155	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2025	2689	512	1115	0	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2026	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Large Unit Output Report

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	39202	1717	7327	7501	3051	3051	2956	2941	1279	1274	1219	1194	1382	1279	578	468	754	717	168	123	130
2000	39839	1717	7327	7501	3051	3051	2956	2940	1280	1275	1230	1206	1430	1329	608	509	873	789	168	140	151
2001	39502	1717	7327	7501	3051	3051	2957	2942	1281	1277	1239	1218	1392	1292	607	485	833	795	172	133	142
2002	39370	1717	7327	7501	3051	3051	2957	2942	1282	1278	1245	1225	1355	1256	600	471	808	773	169	131	141
2003	39402	1717	7327	7501	3051	3051	2955	2941	1282	1280	1251	1232	1541	1217	580	452	778	741	162	125	130
2004	39535	1717	7327	7501	3051	3051	2955	2954	1281	1279	1265	1249	1559	1457	553	425	730	898	152	118	123
2005	39788	1717	7327	7501	3051	3051	2955	2954	1282	1281	1270	1255	1590	1488	732	425	731	898	153	118	118
2006	39832	1717	7327	7501	3051	3051	2954	2953	1282	1281	1274	1262	1820	1518	538	418	718	887	151	118	118
2007	39705	1717	7327	7501	3051	3051	2954	2954	1283	1282	1277	1267	1849	1547	538	418	720	888	151	118	120
2008	39684	1717	7327	7501	3051	3051	2954	2954	1283	1282	1282	1271	1877	1575	522	408	887	868	148	114	118
2009	39755	1717	7327	7501	3051	3051	2998	2953	1282	1282	1284	1274	1704	1602	512	401	888	858	147	116	117
2010	39140	1717	7327	7501	3051	3051	2996	2953	1287	1282	1281	1270	1729	1050	498	388	868	848	143	112	111
2011	39182	1717	7327	7501	3051	3051	2998	2953	1288	1282	1289	1282	1754	0	499	391	873	844	144	114	118
2012	38530	1717	7327	7501	3051	3051	2998	2954	1288	1283	1290	1285	1777	0	847	388	868	841	145	114	122
2013	38528	1717	7327	7501	3051	3051	2998	2954	1288	1283	1292	1287	1800	0	856	378	852	825	141	112	124
2014	35479	1717	7327	7501	0	3051	2998	2998	1287	1282	1293	1288	1821	0	868	370	838	581	141	110	122
2015	31885	1717	7327	7501	0	0	2998	2998	1287	1282	1293	1288	1821	0	868	0	838	581	0	0	0
2016	31685	1717	7327	7501	0	0	2998	2998	1287	1282	1293	1288	1821	0	868	0	838	581	0	0	0
2017	28889	1717	7327	7501	0	0	2996	0	1287	1282	1293	1288	1821	0	868	0	838	581	0	0	0
2018	28889	1717	7327	7501	0	0	2996	0	1287	1282	1293	1288	1821	0	868	0	838	581	0	0	0
2019	26108	1717	7327	7501	0	0	2996	0	1287	1282	0	0	1821	0	868	0	838	581	0	0	0
2020	25240	1717	7327	7501	0	0	2996	0	1287	1282	0	0	1821	0	0	0	838	581	0	0	0
2021	22244	1717	7327	7501	0	0	0	0	1287	1282	0	0	1821	0	0	0	838	581	0	0	0
2022	19675	1717	7327	7501	0	0	0	0	0	0	0	0	1821	0	0	0	838	581	0	0	0
2023	19675	1717	7327	7501	0	0	0	0	0	0	0	0	1821	0	0	0	838	581	0	0	0
2024	19675	1717	7327	7501	0	0	0	0	0	0	0	0	1821	0	0	0	838	581	0	0	0
2025	12084	1717	7327	0	0	0	0	0	0	0	0	0	1821	0	0	0	838	581	0	0	0
2026	9044	1717	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	9044	1717	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	9044	1717	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	9044	1717	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Exhibit No. 10a
TOTAL STRANDED COST CALCULATION

Net Present Value of Contribution Margins	$3,061,696
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	$821,296
Total Adjusted NPV excluding Negative Values	$4,193,985
Book Value	$6,688,384
Stranded Generation Cost	$2,494,399

Scenario: DRI FUEL PRICE Escalation, Minimum PHB Corrections

1 Include State Tax in ECCR
2 Inlude Cap Adds, A&G, ETC in New Generation
3 Corrected Heat Rates, etc in energy model

Exhibit No.___(RJF-10b)

CALCULATION OF NET PRESENT VALUE OF CONTRIBUTION MARGINS

		==========Capacity==========				Capacity	Capacity	Energy	PSH								Net
	Year	Large Units	CT's	PSH	Total	Charges	Revenue	Margins	Magins	Total Costs	O&M	Cap. Add	A&G	Other Tax	Decomm.	Life Ext.	Margin
	1999	7462	835	880	9177	17.82	$163,563	$693,272	$9,290	$833,135	$505,885	$95,311	$49,177	$87,573	$26,425	$68,764	$32,990
	2000	7462	835	880	9177	22.80	$209,244	$773,520	$11,397	$781,284	$519,201	$97,684	$50,401	$87,573	$26,425	$0	$212,877
	2001	7462	835	880	9177	36.99	$339,463	$776,892	$12,079	$800,265	$533,739	$100,615	$51,913	$87,573	$26,425	$0	$328,168
	2002	7462	835	880	9177	35.78	$328,319	$831,513	$12,542	$819,774	$548,672	$103,633	$53,471	$87,573	$26,425	$0	$352,601
	2003	7462	835	880	9177	38.58	$354,051	$862,282	$14,208	$936,032	$571,987	$106,742	$55,075	$87,573	$26,425	$88,230	$294,509
	2004	7462	835	880	9177	42.98	$394,469	$883,804	$13,117	$902,147	$589,582	$109,944	$56,727	$87,573	$26,425	$31,895	$389,243
Disc. Rate	2005	7462	835	880	9177	45.41	$416,739	$922,001	$15,799	$894,221	$608,551	$113,243	$58,429	$87,573	$26,425	$0	$460,319
8.05%	2006	7462	835	880	9177	42.68	$391,699	$995,358	$15,662	$1,015,635	$627,369	$117,082	$60,410	$87,573	$26,425	$96,777	$387,064
	2007	7462	835	880	9177	44.98	$412,791	$1,040,527	$17,447	$946,028	$648,522	$121,051	$62,458	$87,573	$26,425	$0	$524,736
Tax Rate	2008	7462	835	880	9177	47.43	$435,252	$1,086,210	$16,169	$973,623	$669,896	$125,154	$64,575	$87,573	$26,425	$0	$564,008
41.49%	2009	7462	835	880	9177	43.53	$399,454	$1,177,319	$19,446	$1,002,521	$692,362	$129,397	$66,764	$87,573	$26,425	$0	$593,898
	2010	7462	835	880	9177	45.28	$415,545	$1,235,367	$20,263	$1,185,489	$710,916	$133,784	$69,027	$87,573	$26,425	$157,764	$485,686
	2011	7183	835	880	8898	47.39	$421,687	$1,249,219	$20,915	$1,022,564	$709,991	$135,798	$67,571	$82,779	$26,425	$0	$669,258
	2012	7183	835	880	8898	42.76	$380,486	$1,345,552	$24,672	$1,057,885	$738,073	$140,632	$69,977	$82,779	$26,425	$0	$692,825
Post 2014	2013	7183	835	880	8898	44.67	$397,497	$1,406,186	$21,110	$1,087,820	$763,858	$145,839	$72,468	$82,779	$23,077	$0	$736,973
Inflation	2014	6719	835	880	8434	46.19	$389,563	$1,349,226	$22,151	$1,169,285	$790,508	$150,824	$75,048	$82,779	$19,251	$50,876	$591,655
3.56%	2015	5638	0	880	6518	47.83	$311,782	$1,230,574	$22,939	$925,033	$669,132	$122,326	$55,360	$58,964	$19,251	$0	$640,262
	2016	5638	0	880	6518	49.54	$322,881	$1,274,386	$23,756	$952,080	$692,369	$126,680	$57,331	$58,964	$16,735	$0	$668,943
	2017	5167	0	880	6047	51.30	$310,213	$1,199,204	$24,602	$852,499	$597,408	$120,021	$59,372	$58,964	$16,735	$0	$681,519
	2018	5167	0	880	6047	53.13	$321,257	$1,241,896	$25,477	$879,570	$618,091	$124,294	$61,488	$58,964	$16,735	$0	$709,081
	2019	4811	0	880	5691	55.02	$313,107	$1,200,956	$26,384	$888,270	$625,754	$123,143	$63,675	$58,964	$16,735	$0	$652,177
	2020	4667	0	880	5547	56.98	$316,049	$1,213,276	$27,324	$880,479	$622,587	$124,389	$63,050	$56,378	$14,075	$0	$676,170
	2021	4196	0	880	5076	59.00	$299,509	$1,117,433	$28,298	$758,983	$507,265	$115,971	$65,294	$56,378	$14,075	$0	$686,256
	2022	3844	0	880	4724	61.11	$288,662	$1,051,219	$29,304	$736,407	$482,633	$115,702	$67,619	$56,378	$14,075	$0	$632,778
	2023	3844	0	880	4724	63.28	$298,939	$1,088,642	$30,347	$752,970	$499,231	$119,821	$70,026	$56,378	$7,514	$0	$664,958
	2024	3844	0	880	4724	65.53	$309,581	$1,127,399	$31,427	$776,917	$516,420	$124,087	$72,519	$56,378	$7,514	$0	$691,490
	2025	2689	0	880	3569	67.87	$242,216	$710,970	$32,546	$488,561	$329,040	$71,852	$44,984	$33,770	$8,916	$0	$497,171
	2026	1627	0	880	2507	70.28	$176,199	$581,386	$33,705	$398,117	$259,004	$65,120	$37,728	$27,349	$8,916	$0	$393,173
	2027	1627	0	880	2507	72.78	$182,471	$602,084	$34,905	$410,707	$267,933	$67,439	$39,071	$27,349	$8,916	$0	$408,753
	2028	1627	0	880	2507	75.38	$188,967	$623,518	$36,147	$423,745	$277,179	$69,839	$40,462	$27,349	$8,916	$0	$424,888
	2029	1627	0	880	2507	78.06	$195,695	$645,716	$37,434	$437,248	$286,755	$72,326	$41,902	$27,349	$8,916	$0	$441,597

NPV of Net Margins After Tax $3,081,896

Exhibit No.___(RJF-10c)
PUMPED STORAGE UNITS
ECONOMIC BENEFITS AND OPERATIONS

YEAR	MW	BENEFIT	GEN MWH	CF	PUMPING COST	GEN. VALUE	DAYS	HOURS	LOSS FACTOR
1999	1693	17872630	2302480	15.5	16.92	31.79	246	1360	1.42
2000	1693	21926960	2527649	17	17.38	33.35	263	1493	1.42
2001	1693	23238280	2454850	16.6	18.01	35.05	248	1450	1.42
2002	1693	24129980	2368507	16	18.31	36.19	245	1399	1.42
2003	1693	27334820	2470087	16.7	19.11	38.21	250	1459	1.42
2004	1342	20003010	1897588	16.1	19.03	37.56	255	1414	1.42
2005	1342	24094000	2133780	18.2	19.78	39.38	280	1590	1.42
2006	1342	23884430	2230404	19	20.05	39.18	290	1662	1.42
2007	1342	26606450	2277374	19.4	21.04	41.56	290	1697	1.42
2008	1342	24658320	2207590	18.8	21.47	41.66	287	1645	1.42
2009	1342	29655320	2383392	20.3	22.46	44.33	298	1776	1.42
2010	1342	30900890	2459886	20.9	23.27	45.6	299	1833	1.42
2011	1342	31895700	2522960	21.5	24.26	47.08	305	1880	1.42
2012	1342	37625480	2587376	22	25.57	50.86	317	1928	1.42
2013	1342	32192910	2445124	20.8	25.47	49.33	314	1822	1.42
2014	1342	33779850	2494778	21.2	26.68	51.42	323	1859	1.42

Scenario: **DRI FUEL PRICE Escalation, Minimum PHB Corrections**

Annual Total

Exhibit No.___(RJF-16d)

Large Units
Capacity mW

UNIT		Conesvle 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddystn 2	Eddystn 1	Cromby 1	Cromby 2	Eddystn 3	Eddystn 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2000	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2001	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2002	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2003	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2004	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2005	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2006	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2007	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2008	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2009	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2010	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2011	7183	512	1115	1155	464	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2012	7183	512	1115	1155	464	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2013	7183	512	1115	1155	464	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2014	6719	512	1115	1155	0	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2015	5638	512	1115	1155	0	0	471	471	176	176	178	178	302	0	144	0	380	380	0	0	0
2016	5638	512	1115	1155	0	0	471	471	176	176	178	178	302	0	144	0	380	380	0	0	0
2017	5167	512	1115	1155	0	0	471	0	176	176	178	178	302	0	144	0	380	380	0	0	0
2018	5167	512	1115	1155	0	0	471	0	176	176	178	178	302	0	144	0	380	380	0	0	0
2019	4811	512	1115	1155	0	0	471	0	176	176	0	0	302	0	144	0	380	380	0	0	0
2020	4667	512	1115	1155	0	0	471	0	176	176	0	0	302	0	0	0	380	380	0	0	0
2021	4196	512	1115	1155	0	0	0	0	176	176	0	0	302	0	0	0	380	380	0	0	0
2022	3844	512	1115	1155	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2023	3844	512	1115	1155	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2024	3844	512	1115	1155	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2025	2689	512	1115	0	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2026	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Large Unit Output Report

UNIT		Conesvle 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddystn 2	Eddystn 1	Cromby 1	Cromby 2	Eddystn 3	Eddystn 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	39110	1718	7327	7590	3052	3052	2938	2937	1279	1279	1254	1235	1371	1267	580	414	698	682	186	130	135
2000	39551	1718	7327	7590	3052	3052	2938	2938	1280	1279	1262	1245	1431	1327	630	456	768	731	218	153	158
2001	39411	1718	7327	7590	3052	3052	2938	2938	1281	1279	1268	1253	1481	1376	581	417	703	668	197	136	144
2002	39646	1718	7327	7590	3052	3052	2938	2938	1281	1279	1271	1257	1569	1409	680	421	710	677	193	138	145
2003	39712	1718	7327	7590	3052	3052	2940	2938	1281	1280	1275	1263	1603	1490	701	404	681	648	186	133	140
2004	39861	1718	7327	7590	3052	3052	2940	2940	1282	1280	1277	1265	1623	1517	742	379	639	608	174	126	131
2005	39684	1718	7327	7590	3052	3052	2940	2940	1282	1281	1280	1270	1655	1550	762	388	617	588	168	118	128
2006	39827	1718	7327	7590	3052	3052	2941	2940	1282	1281	1283	1274	1687	1582	780	375	632	603	173	122	133
2007	39695	1718	7327	7590	3052	3052	2997	2939	1282	1281	1284	1278	1718	1611	796	382	611	583	160	119	128
2008	39912	1718	7327	7590	3052	3052	2997	2939	1282	1281	1287	1280	1745	1640	815	350	591	584	162	115	125
2009	40051	1718	7327	7590	3052	3052	2997	2940	1282	1282	1289	1283	1772	1668	832	380	608	580	168	120	131
2010	40088	1718	7327	7590	3052	3052	2997	2940	1282	1282	1291	1285	1796	1694	847	349	601	564	164	117	126
2011	38369	1718	7327	7590	3052	3052	2997	2941	1283	1282	1292	1288	1822	0	862	340	575	549	158	114	126
2012	38491	1718	7327	7590	3052	3052	2997	2942	1283	1283	1294	1290	1845	0	876	350	586	597	185	119	132
2013	38515	1718	7327	7590	3052	3052	2997	2997	1282	1282	1294	1290	1864	0	888	341	584	552	161	115	129
2014	35462	1718	7327	7590	0	3052	2997	2997	1283	1283	1295	1292	1883	0	901	334	571	541	158	113	127
2015	31678	1718	7327	7590	0	0	2997	2997	1283	1283	1295	1292	1883	0	901	0	571	541	0	0	0
2016	31678	1718	7327	7590	0	0	2997	2997	1283	1283	1295	1292	1883	0	901	0	571	541	0	0	0
2017	28681	1718	7327	7590	0	0	2997	0	1283	1283	1295	1292	1883	0	901	0	571	541	0	0	0
2018	28681	1718	7327	7590	0	0	2997	0	1283	1283	1295	1292	1883	0	901	0	571	541	0	0	0
2019	26094	1718	7327	7590	0	0	2997	0	1283	1283	0	0	1883	0	901	0	571	541	0	0	0
2020	25193	1718	7327	7590	0	0	2997	0	1283	1283	0	0	1883	0	0	0	571	541	0	0	0
2021	22196	1718	7327	7590	0	0	0	0	1283	1283	0	0	1883	0	0	0	571	541	0	0	0
2022	19630	1718	7327	7590	0	0	0	0	0	0	0	0	1883	0	0	0	571	541	0	0	0
2023	19630	1718	7327	7590	0	0	0	0	0	0	0	0	1883	0	0	0	571	541	0	0	0
2024	19630	1718	7327	7590	0	0	0	0	0	0	0	0	1883	0	0	0	571	541	0	0	0
2025	12040	1718	7327	0	0	0	0	0	0	0	0	0	1883	0	0	0	571	541	0	0	0
2026	9045	1718	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	9045	1718	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	9045	1718	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	9045	1718	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fuel Cost $ (1000)

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddyste 2	Eddyste 1	Cromby 1	Cromby 2	Eddyste 3	Eddyste 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	378233	17	32566	34106	15865	16044	22496	22687	15407	15368	18527	18241	23010	21517	10828	10450	18733	18057	5321	4200	4894
2000	342345	17	32393	33925	15781	15950	22381	22573	15633	15602	18898	18645	24360	22839	11330	12048	21839	20818	6327	5187	5814
2001	344455	17	32798	34315	15962	16142	22836	22833	15901	15877	19308	19061	25636	24093	10801	11589	20787	20085	6087	4888	5683
2002	356340	17	33143	34710	16148	16328	22899	23098	16173	16152	19803	19472	27618	25082	12641	12278	22057	21323	6317	5188	6021
2003	363828	17	33524	35108	16331	16518	23187	23370	16453	16435	20078	19684	28703	27118	13256	12373	22227	21488	6400	5261	6118
2004	368412	17	33908	35513	16519	16708	23434	23640	16733	16717	20444	20261	29535	27932	14268	12184	21879	21145	6323	5201	6054
2005	375360	17	34298	35921	16708	16898	23708	23918	17021	17007	20842	20876	30644	29023	14887	12344	22170	21429	6447	5203	6197
2006	392697	17	35630	37315	17358	17553	24631	24849	17428	17415	21383	21233	31968	30318	15614	13324	23856	23181	7008	5898	6818
2007	408083	17	37012	38782	18031	18235	26072	25798	17826	17818	21815	21779	33278	31601	16335	13577	24418	23830	7152	5828	6963
2008	418512	17	38449	40286	18730	18942	27083	26803	18252	18245	22474	22353	34639	32933	17084	13845	24900	24100	7297	5956	7144
2009	438953	17	39940	41829	19457	19677	28135	27845	18685	18680	23041	22933	36018	34783	17844	15001	27007	26168	7963	6546	7688
2010	453738	17	41490	43452	20212	20441	29226	28932	19131	19126	23618	23521	37402	35641	18610	15372	27682	26828	8173	6735	8127
2011	430314	17	42938	44968	20918	21154	30246	29950	19559	19555	24170	24084	38739	0	19354	15628	28148	27284	8357	6903	8348
2012	449032	17	44437	46538	21648	21892	31302	31004	19997	19994	24732	24656	40085	0	20104	16797	30617	29393	8065	7558	9176
2013	462432	17	45987	48162	22403	22658	32394	32084	20429	20426	25283	25215	41394	0	20835	17090	31158	29923	9298	7642	9435
2014	453089	17	47592	49843	0	23447	33525	33825	20885	20882	25863	25803	42753	0	21594	17457	31834	30585	9559	7878	9748
2015	396785	18	49321	51642	0	0	34728	35038	21624	21624	26784	26718	44268	0	22368	0	32972	31688	0	0	0
2016	412980	18	51077	53480	0	0	35982	36284	22393	22393	27737	27670	45842	0	23162	0	34148	32818	0	0	0
2017	390110	18	52895	55384	0	0	37243	0	23191	23191	28724	28655	47474	0	23987	0	35362	33985	0	0	0
2018	403997	20	54779	57358	0	0	38568	0	24018	24016	29747	29675	49164	0	24841	0	36621	35195	0	0	0
2019	354838	20	56728	59397	0	0	39941	0	24871	24871	0	0	50914	0	25725	0	37924	36447	0	0	0
2020	342904	21	58748	61512	0	0	41363	0	25757	25757	0	0	52726	0	0	0	39275	37745	0	0	0
2021	312275	22	60838	63702	0	0	0	0	26673	26673	0	0	54604	0	0	0	40673	39089	0	0	0
2022	288146	23	63005	65970	0	0	0	0	0	0	0	0	56547	0	0	0	42121	40480	0	0	0
2023	277681	24	65248	68318	0	0	0	0	0	0	0	0	58560	0	0	0	43620	41921	0	0	0
2024	287577	24	67571	70750	0	0	0	0	0	0	0	0	60645	0	0	0	45173	43414	0	0	0
2025	224545	25	69978	0	0	0	0	0	0	0	0	0	62804	0	0	0	46781	44958	0	0	0
2026	72494	26	72468	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	75074	27	75047	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	77747	28	77718	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	80515	29	80488	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fuel Cost $/MWh

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddyste 2	Eddyste 1	Cromby 1	Cromby 2	Eddyste 3	Eddyste 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	8.38	0.01	4.44	4.49	5.20	5.28	7.85	7.72	12.05	12.04	14.77	14.77	16.79	16.88	17.74	25.28	28.92	27.28	28.61	32.82	36.25
2000	8.88	0.01	4.42	4.47	5.17	5.23	7.62	7.88	12.21	12.21	14.87	14.88	17.02	17.21	17.98	28.47	28.18	28.61	28.28	33.77	37.18
2001	8.74	0.01	4.47	4.52	5.23	5.29	7.70	7.77	12.41	12.41	15.23	15.23	17.31	17.51	18.28	27.78	28.58	30.02	30.90	35.78	38.33
2002	8.99	0.01	4.52	4.57	5.29	5.35	7.79	7.86	12.63	12.63	15.49	15.49	17.60	17.80	18.50	29.18	31.07	31.50	32.73	37.58	41.52
2003	9.18	0.01	4.58	4.63	5.35	5.41	7.88	7.95	12.84	12.84	15.75	15.74	17.91	18.10	18.91	30.63	32.64	33.11	34.41	38.58	43.70
2004	9.29	0.01	4.63	4.68	5.41	5.47	7.97	8.04	13.05	13.08	16.01	16.02	18.20	18.41	18.23	32.15	34.24	34.72	36.34	41.84	46.21
2005	9.48	0.01	4.68	4.73	5.47	5.54	8.08	8.14	13.28	13.28	16.28	16.28	18.52	18.72	18.54	33.73	35.93	36.44	38.38	44.08	48.41
2006	9.86	0.01	4.88	4.92	5.69	5.75	8.38	8.45	13.58	13.58	16.67	16.67	18.95	18.18	20.02	35.53	37.91	38.44	40.51	46.71	51.26
2007	10.18	0.01	5.05	5.11	5.81	5.97	8.70	8.78	13.80	13.81	17.07	17.07	19.39	19.82	20.47	37.81	39.98	40.53	42.57	48.97	54.13
2008	10.51	0.01	5.25	5.31	6.14	6.21	9.04	9.12	14.24	14.24	17.46	17.46	19.85	20.06	20.96	39.98	42.13	42.73	45.04	51.78	57.16
2009	10.88	0.01	5.45	5.51	6.38	6.45	9.39	9.47	14.57	14.57	17.68	17.87	20.33	20.56	21.45	41.67	44.42	45.12	47.40	54.55	60.20
2010	11.32	0.01	5.66	5.72	6.62	6.70	9.75	9.84	14.92	14.92	18.29	18.30	20.80	21.04	21.97	44.05	46.84	47.57	49.84	57.58	63.49
2011	11.22	0.01	5.88	5.92	6.85	6.93	10.09	10.18	15.24	15.25	18.71	18.70	21.26	0.00	22.45	45.98	48.85	48.70	52.58	60.55	66.24
2012	11.67	0.01	6.08	6.13	7.09	7.17	10.44	10.54	15.58	15.58	19.11	19.11	21.73	0.00	22.95	47.99	51.11	51.84	55.08	63.51	69.52
2013	12.01	0.01	6.29	6.35	7.34	7.42	10.81	10.91	15.84	15.93	19.54	19.55	22.21	0.00	23.48	50.12	53.35	54.21	57.78	66.45	73.14
2014	12.78	0.01	6.50	6.57	0.00	7.68	11.18	11.29	16.20	16.20	19.97	19.97	22.70	0.00	23.97	52.27	55.78	56.53	60.50	69.73	76.74
2015	12.58	0.01	6.73	6.80	0.00	0.00	11.58	11.69	16.85	16.85	20.68	20.66	23.51	0.00	24.82	0.00	57.74	58.57	0.00	0.00	0.00
2016	13.04	0.01	6.97	7.05	0.00	0.00	12.00	12.11	17.45	17.45	21.42	21.42	24.35	0.00	25.71	0.00	59.80	60.66	0.00	0.00	0.00
2017	13.60	0.01	7.22	7.30	0.00	0.00	12.43	0.00	18.08	18.08	22.18	22.18	25.21	0.00	26.62	0.00	61.93	62.82	0.00	0.00	0.00
2018	14.08	0.01	7.48	7.56	0.00	0.00	12.87	0.00	18.72	18.72	22.97	22.97	26.11	0.00	27.57	0.00	64.13	65.06	0.00	0.00	0.00
2019	13.68	0.01	7.74	7.63	0.00	0.00	13.33	0.00	19.38	19.39	0.00	0.00	27.04	0.00	28.55	0.00	66.42	67.37	0.00	0.00	0.00
2020	13.61	0.01	8.02	8.10	0.00	0.00	13.80	0.00	20.08	20.08	0.00	0.00	28.00	0.00	0.00	0.00	68.78	69.77	0.00	0.00	0.00
2021	14.07	0.01	8.30	8.39	0.00	0.00	0.00	0.00	20.78	20.78	0.00	0.00	29.00	0.00	0.00	0.00	71.23	72.25	0.00	0.00	0.00
2022	13.86	0.01	8.60	8.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.03	0.00	0.00	0.00	73.77	74.82	0.00	0.00	0.00
2023	14.15	0.01	8.91	9.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.10	0.00	0.00	0.00	76.39	77.49	0.00	0.00	0.00
2024	14.85	0.01	9.22	9.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.21	0.00	0.00	0.00	79.11	80.25	0.00	0.00	0.00
2025	16.65	0.01	9.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.35	0.00	0.00	0.00	81.93	83.10	0.00	0.00	0.00
2026	9.01	0.02	9.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	9.30	0.02	10.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	9.60	0.02	10.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	9.90	0.02	10.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Market Energy Prices $/MWh

UNIT		Conowin 1	Limerk 2	Limerk 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddystn 2	Eddystn 1	Cromby 1	Cromby 2	Eddystn 3	Eddystn 4	Delawr 7	Delawr 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	26.11	24.52	24.53	24.53	24.53	24.53	24.53	24.53	24.55	24.57	24.85	24.99	29.10	29.55	30.97	41.57	42.21	42.96	47.53	54.20	58.94
2000	25.62	26.43	26.43	26.43	26.43	26.43	26.43	26.43	26.45	26.46	26.73	26.87	31.14	31.50	33.14	44.24	44.86	45.73	49.80	56.58	62.78
2001	26.26	26.68	26.68	26.66	26.66	26.68	26.68	26.68	26.66	26.70	26.82	27.04	30.83	31.25	34.25	46.48	47.13	48.03	52.17	60.32	66.33
2002	26.81	28.08	28.08	28.08	28.08	28.08	28.08	28.09	28.09	28.11	28.32	28.45	31.78	32.72	34.04	49.58	50.34	51.25	56.87	64.43	71.44
2003	27.40	28.95	28.96	28.96	28.96	28.96	28.95	28.96	28.97	28.97	29.17	29.27	32.58	32.85	34.65	52.48	53.29	54.30	58.78	68.11	75.51
2004	27.80	29.62	29.63	29.63	29.62	29.62	29.62	29.62	29.62	29.65	29.82	29.84	33.07	33.44	34.53	55.48	56.32	57.39	63.40	72.57	80.30
2005	29.22	30.68	30.68	30.68	30.68	30.68	30.68	30.68	30.69	30.69	30.86	30.96	34.02	34.35	35.39	58.68	58.81	60.77	67.22	77.35	84.51
2006	30.07	32.67	32.67	32.67	32.67	32.67	32.67	32.68	32.68	32.69	32.84	32.93	36.03	36.38	37.49	62.83	63.71	64.83	71.87	82.90	90.48
2007	31.63	34.02	34.02	34.02	34.02	34.02	34.02	34.02	34.01	34.03	34.18	34.28	37.24	37.59	38.63	66.43	67.49	68.80	75.81	87.38	96.05
2008	32.58	35.42	35.43	35.43	35.43	35.43	35.42	35.43	35.42	35.44	35.55	35.64	38.50	38.85	39.88	70.29	71.38	72.77	80.62	92.73	101.77
2009	33.80	37.06	37.06	37.06	37.06	37.06	37.06	37.05	37.06	37.05	37.96	38.08	40.87	41.31	42.35	75.03	76.27	77.85	85.00	98.83	108.38
2010	34.66	39.57	39.58	39.58	39.58	39.58	39.57	39.58	39.58	39.58	39.67	39.77	42.55	42.89	43.95	79.72	80.64	82.51	90.82	104.85	114.92
2011	36.48	41.14	41.15	41.16	41.14	41.14	41.14	41.14	41.13	41.16	41.25	41.30	43.98	0.00	45.32	83.91	85.23	86.98	98.26	110.86	120.48
2012	37.73	43.78	43.78	43.79	43.78	43.78	43.78	43.78	43.78	43.78	43.86	43.93	46.58	0.00	47.97	89.13	90.10	92.28	102.10	117.65	127.83
2013	38.07	45.57	45.57	45.57	45.57	45.57	45.57	45.56	45.59	45.58	45.65	45.72	48.24	0.00	48.58	93.83	94.82	97.38	107.68	124.82	135.21
2014	40.68	47.51	47.51	47.51	0.00	47.51	47.51	47.51	47.50	47.50	47.58	47.63	50.08	0.00	51.33	98.80	100.15	102.57	113.45	131.52	142.65
2015	41.49	49.20	49.20	49.20	0.00	0.00	49.20	49.20	49.18	49.19	49.26	49.32	51.84	0.00	53.18	0.00	103.74	106.27	0.00	0.00	0.00
2016	42.97	50.95	50.95	50.95	0.00	0.00	50.95	50.95	50.94	50.95	51.03	51.08	53.69	0.00	55.07	0.00	107.43	110.08	0.00	0.00	0.00
2017	44.65	52.77	52.77	52.77	0.00	0.00	52.76	0.00	52.75	52.76	52.85	52.90	55.60	0.00	57.03	0.00	111.25	113.97	0.00	0.00	0.00
2018	46.24	54.85	54.85	54.85	0.00	0.00	54.64	0.00	54.83	54.84	54.73	54.78	57.58	0.00	59.06	0.00	115.21	118.03	0.00	0.00	0.00
2019	48.04	56.58	56.58	56.58	0.00	0.00	56.58	0.00	56.57	56.58	0.00	0.00	59.63	0.00	61.18	0.00	119.32	122.23	0.00	0.00	0.00
2020	49.88	58.81	58.81	58.81	0.00	0.00	58.80	0.00	58.59	58.60	0.00	0.00	61.75	0.00	0.00	0.00	123.56	126.58	0.00	0.00	0.00
2021	51.71	60.69	60.69	60.69	0.00	0.00	0.00	0.00	60.67	60.68	0.00	0.00	63.95	0.00	0.00	0.00	127.98	131.09	0.00	0.00	0.00
2022	53.85	62.85	62.85	62.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.23	0.00	0.00	0.00	132.52	135.76	0.00	0.00	0.00
2023	55.77	65.09	65.09	65.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.58	0.00	0.00	0.00	137.23	140.58	0.00	0.00	0.00
2024	57.75	67.41	67.41	67.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.02	0.00	0.00	0.00	142.12	145.60	0.00	0.00	0.00
2025	61.86	69.81	69.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.55	0.00	0.00	0.00	147.18	150.78	0.00	0.00	0.00
2026	58.98	72.29	72.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	61.06	74.87	74.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	63.25	77.53	77.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	65.50	80.29	80.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Market Energy Revenues ($1000)

UNIT		Conowin 1	Limerk 2	Limerk 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddystn 2	Eddystn 1	Cromby 1	Cromby 2	Eddystn 3	Eddystn 4	Delawr 7	Delawr 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	1021505	42131	179709	186155	74852	74852	72081	72052	31404	31354	31165	30657	39896	37437	18552	17208	29379	29442	8840	7048	8092
2000	1115865	45400	193636	200597	80658	80658	77679	77658	33854	33812	33727	33448	44555	41917	20676	20131	34456	33431	10714	8858	9963
2001	1121347	45829	195480	202482	81421	81421	78404	78380	34177	34143	34132	33884	45684	42988	20242	19373	33135	32133	10277	8204	9551
2002	1187858	48237	205754	213135	85700	85700	82532	82519	35880	35849	35882	35759	49866	46087	23145	20872	35738	34686	10837	8882	10358
2003	1228100	49741	212170	219781	88372	88372	85123	85113	37113	37087	37187	36872	52103	49211	24287	21183	38292	35242	11120	9056	10571
2004	1252210	50890	217088	224857	90413	90413	87081	87082	37973	37948	38079	37873	53674	50722	25424	21010	35889	34850	11031	8888	10518
2005	1297361	52708	224826	232801	93643	93643	90220	90213	39340	39320	39505	39317	56295	53247	26968	21478	36781	35731	11283	9127	10817
2006	1348058	58127	239405	247883	99718	99718	96082	96078	41889	41881	42132	41958	60786	57556	29241	23485	40265	39155	12433	10114	12034
2007	1446580	58444	249280	258232	103833	103833	101947	99976	43601	43587	43892	43735	63902	60552	30820	24048	41238	40111	12753	10388	12381
2008	1505722	60857	259561	268893	108120	108120	108158	104124	45412	45400	45758	45618	67181	63713	32500	24800	42190	41043	13080	10884	12721
2009	1618272	65030	277418	287371	115540	115540	113452	111282	48538	48529	48955	48826	72595	68899	35235	27910	48371	45154	14432	11850	14198
2010	1688103	67885	288886	300388	120784	120784	118581	118356	50748	50740	51219	51103	76513	72664	37227	27824	47778	48838	14895	12268	14710
2011	1670633	70680	301481	312287	125572	125572	123292	121002	52775	52768	53294	53190	80130	0	39070	28526	48008	47750	15308	12840	15181
2012	1784584	75214	320824	332333	133628	133628	131202	128803	56178	56172	56760	56685	85950	0	42018	31195	63872	62322	16846	14000	16074
2013	1868618	78289	333872	345801	139084	139084	138558	136558	58441	58438	58070	58985	89019	0	44039	32031	66432	63762	17337	14331	17442
2014	1802315	81618	348140	360829	0	145006	142374	142373	60941	60938	61828	61544	94268	0	46252	33634	57185	55480	17925	14862	18118
2015	1828358	84528	360498	373438	0	0	147438	147438	63104	63117	63814	63725	97618	0	47813	0	58233	57484	0	0	0
2016	1887388	87537	373332	388733	0	0	152687	152687	65351	65364	66085	65994	101094	0	49619	0	61342	60541	0	0	0
2017	1500314	90853	388823	400500	0	0	158123	0	67677	67681	68438	68344	104693	0	51388	0	63528	61880	0	0	0
2018	1645893	93881	400386	414758	0	0	163752	0	70086	70101	70875	70777	108420	0	53215	0	65767	63855	0	0	0
2019	1557784	97223	414840	429524	0	0	168582	0	72581	72587	0	0	112280	0	55109	0	68129	66129	0	0	0
2020	1538180	100884	429401	444815	0	0	175619	0	75185	75181	0	0	116277	0	0	0	70555	68483	0	0	0
2021	1429708	104258	444888	460850	0	0	0	0	77841	77858	0	0	120418	0	0	0	73088	70825	0	0	0
2022	1319385	107980	460519	477049	0	0	0	0	0	0	0	0	124703	0	0	0	75668	73448	0	0	0
2023	1388333	111824	476913	494032	0	0	0	0	0	0	0	0	129143	0	0	0	78361	76080	0	0	0
2024	1414876	115805	493892	511820	0	0	0	0	0	0	0	0	133740	0	0	0	81151	78768	0	0	0
2025	935515	119928	511474	0	0	0	0	0	0	0	0	0	138501	0	0	0	84040	81572	0	0	0
2026	853880	124187	529883	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	877158	128819	548538	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	701283	133198	568087	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	728231	137940	588291	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Energy Margins ($1000)

UNIT		Conowingo 1	Limerick 2	Limerick 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemaugh 2	Conemaugh 1	Keystone 2	Keystone 1	Eddystone 2	Eddystone 1	Cromby 1	Cromby 2	Eddystone 3	Eddystone 4	Delaware 7	Delaware 8	Schuylkill 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	693272	42114	147143	152048	58907	58808	49583	49385	15897	15886	12639	12616	16878	15920	7924	6750	10848	10385	3519	2788	3198
2000	773520	45383	161257	168672	64877	64699	55299	55085	18221	18210	14829	14803	20195	19078	9548	8065	12817	12515	4387	3492	4068
2001	778892	45812	162714	168177	65450	65279	55788	55558	18278	18268	14828	14803	20628	18903	9441	7784	12338	12048	4190	3338	3888
2002	831513	48220	172611	178425	69554	69372	59833	59420	19807	19787	16309	16287	22247	21015	10504	8594	13681	13373	4620	3708	4338
2003	882282	49724	178848	184672	72041	71856	61956	61743	20860	20852	17111	17088	23400	22093	11031	8620	14065	13754	4720	3787	4453
2004	883804	50873	183160	189344	73894	73707	63657	63442	21240	21232	17635	17612	24139	22790	11358	8835	14110	13805	4708	3798	4465
2005	922001	52691	190527	196970	78934	78745	68512	68295	22318	22313	18663	18641	25851	24224	12081	9132	14811	14302	4848	3924	4820
2006	985358	56110	203775	210878	82358	82183	71451	71227	24473	24468	20749	20728	28818	27238	13627	10181	16308	15874	5424	4418	5216
2007	1040527	58427	212277	218470	85802	85598	75875	74180	25775	25769	21977	21956	30824	28951	14493	10471	16822	16481	5601	4570	5406
2008	1086210	60840	221132	228627	89390	89178	79073	77321	27180	27155	23285	23265	32552	30780	15418	10759	17290	16943	5783	4708	5577
2009	1177318	65022	237478	245542	96092	95872	85317	83447	29853	29840	25914	25893	35579	34618	17391	12009	19364	18988	6469	5313	6312
2010	1235307	67968	248490	258937	100572	100343	89365	87424	31817	31814	27601	27582	39111	37023	18617	12452	20097	19710	6722	5533	6583
2011	1249218	70063	258543	267328	104654	104418	93048	91052	33218	33213	29124	29106	41391	0	19718	12902	20858	20408	6949	5737	6835
2012	1345552	75197	278307	285785	111980	111738	99900	97798	36181	36178	32029	32009	45865	0	21814	14398	23355	22828	7761	6442	7690
2013	1408186	78268	287935	297738	116481	116428	104165	103874	38012	38010	33787	33770	48525	0	23204	14941	24274	23839	8038	6689	8007
2014	1348228	81602	300548	310786	0	121559	108849	108548	40058	40058	35757	35741	51515	0	24658	15577	25351	24804	8388	6983	8370
2015	1230574	84510	311177	321798	0	0	112712	112402	41480	41493	37030	37007	53353	0	25547	0	26261	25806	0	0	0
2016	1274388	87518	322255	333253	0	0	116725	116403	42958	42971	38348	38324	56252	0	26457	0	27108	26725	0	0	0
2017	1198204	90834	333728	345118	0	0	120880	0	44488	44500	39714	39889	57218	0	27398	0	28164	27875	0	0	0
2018	1241098	93861	345808	357402	0	0	125184	0	46070	46085	41128	41102	59258	0	28374	0	29188	28880	0	0	0
2019	1200956	97203	357812	370127	0	0	129641	0	47710	47728	0	0	61368	0	29384	0	30205	29682	0	0	0
2020	1213278	100883	370853	383303	0	0	134256	0	49408	49424	0	0	63551	0	0	0	31280	30738	0	0	0
2021	1117433	104248	383849	396948	0	0	0	0	51168	51185	0	0	65812	0	0	0	32393	31832	0	0	0
2022	1051219	107957	397514	411079	0	0	0	0	0	0	0	0	68156	0	0	0	33547	32966	0	0	0
2023	1088842	111800	411085	425714	0	0	0	0	0	0	0	0	70583	0	0	0	34741	34138	0	0	0
2024	1127389	115781	428321	440870	0	0	0	0	0	0	0	0	73095	0	0	0	35978	35354	0	0	0
2025	710970	119903	441498	0	0	0	0	0	0	0	0	0	75697	0	0	0	37258	36613	0	0	0
2026	581388	124171	457215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	602084	128592	473492	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	623518	133170	490348	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	645718	137911	507605	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Unit Capacity Factors

UNIT		Conowingo 1	Limerick 2	Limerick 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemaugh 2	Conemaugh 1	Keystone 2	Keystone 1	Eddystone 2	Eddystone 1	Cromby 1	Cromby 2	Eddystone 3	Eddystone 4	Delaware 7	Delaware 8	Schuylkill 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	59.85	38.30	75.01	75.02	75.09	75.09	71.23	71.18	82.98	82.78	80.42	79.20	51.82	51.84	47.49	23.51	20.91	19.88	16.85	11.97	9.28
2000	60.51	38.30	75.01	75.02	75.09	75.09	71.23	71.21	83.02	82.89	80.93	79.84	54.09	54.30	48.84	25.84	23.07	21.98	19.57	14.08	10.93
2001	60.29	38.30	75.01	75.02	75.09	75.09	71.23	71.21	83.09	82.98	81.32	80.36	55.98	56.30	48.85	23.88	21.12	20.10	17.85	12.52	9.90
2002	60.65	38.30	75.01	75.02	75.09	75.09	71.23	71.21	83.09	82.98	81.51	80.61	59.31	57.65	53.81	23.91	21.33	20.34	17.49	12.78	9.97
2003	60.75	38.30	75.01	75.02	75.09	75.09	71.28	71.23	83.09	83.02	81.77	81.00	60.59	61.29	55.57	22.84	20.46	19.50	16.86	12.24	9.83
2004	60.67	38.30	75.01	75.02	75.09	75.09	71.28	71.28	83.15	83.02	81.90	81.13	61.35	62.07	58.82	21.52	19.20	18.29	15.78	11.42	9.01
2005	60.71	38.30	75.01	75.02	75.09	75.09	71.28	71.28	83.15	83.09	82.09	81.45	62.56	63.42	60.41	20.79	18.54	17.88	15.22	10.88	8.80
2006	60.93	38.30	75.01	75.02	75.09	75.09	71.28	71.28	83.15	83.09	82.29	81.70	63.77	64.73	61.83	21.30	18.80	18.11	15.07	11.23	9.15
2007	61.03	38.30	75.01	75.02	75.09	75.09	72.64	71.23	83.15	83.09	82.35	81.83	64.86	65.92	63.20	20.56	18.35	17.51	15.22	10.86	8.87
2008	61.09	38.30	75.01	75.02	75.09	75.09	72.64	71.23	83.15	83.09	82.54	82.09	65.96	67.10	64.61	19.88	17.75	18.94	14.68	10.59	8.80
2009	61.27	38.30	75.01	75.02	75.09	75.09	72.64	71.28	83.15	83.15	82.67	82.28	66.98	68.25	65.98	20.45	18.28	17.42	15.22	11.05	9.01
2010	61.30	38.30	75.01	75.02	75.09	75.09	72.64	71.28	83.15	83.15	82.79	82.41	67.86	69.31	67.15	18.82	17.75	18.94	14.86	10.77	8.80
2011	60.98	38.30	75.01	75.02	75.09	75.09	72.64	71.28	83.22	83.15	82.88	82.60	68.87	0.00	68.33	18.31	17.27	18.19	14.41	10.48	8.86
2012	61.18	38.30	75.01	75.02	75.09	75.09	72.64	71.30	83.22	83.22	82.98	82.73	69.74	0.00	68.44	18.88	17.88	17.03	14.95	10.86	9.06
2013	61.21	38.30	75.01	75.02	75.09	75.09	72.64	72.64	83.15	83.15	82.99	82.73	70.48	0.00	70.40	19.37	17.84	18.58	14.59	10.59	8.87
2014	60.25	38.30	75.01	75.02	0.00	75.09	72.64	72.64	83.22	83.22	83.05	82.86	71.18	0.00	71.43	18.87	17.15	18.25	14.31	10.40	8.73
2015	64.14	38.30	75.01	75.02	0.00	0.00	72.64	72.64	83.22	83.22	83.05	82.86	71.18	0.00	71.43	0.00	17.15	18.25	0.00	0.00	0.00
2016	64.14	38.30	75.01	75.02	0.00	0.00	72.64	72.64	83.22	83.22	83.05	82.86	71.18	0.00	71.43	0.00	17.15	18.25	0.00	0.00	0.00
2017	63.37	38.30	75.01	75.02	0.00	0.00	72.64	0.00	83.22	83.22	83.05	82.86	71.18	0.00	71.43	0.00	17.18	18.25	0.00	0.00	0.00
2018	63.37	38.30	75.01	75.02	0.00	0.00	72.64	0.00	83.22	83.22	83.05	82.86	71.18	0.00	71.43	0.00	17.18	18.25	0.00	0.00	0.00
2019	61.92	38.30	75.01	75.02	0.00	0.00	72.64	0.00	83.22	83.22	0.00	0.00	71.18	0.00	71.43	0.00	17.15	18.25	0.00	0.00	0.00
2020	61.62	38.30	75.01	75.02	0.00	0.00	72.64	0.00	83.22	83.22	0.00	0.00	71.18	0.00	0.00	0.00	17.15	18.25	0.00	0.00	0.00
2021	60.39	38.30	75.01	75.02	0.00	0.00	0.00	0.00	83.22	83.22	0.00	0.00	71.18	0.00	0.00	0.00	17.15	18.25	0.00	0.00	0.00
2022	58.30	38.30	75.01	75.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.18	0.00	0.00	0.00	17.15	18.25	0.00	0.00	0.00
2023	58.30	38.30	75.01	75.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.18	0.00	0.00	0.00	17.15	18.25	0.00	0.00	0.00
2024	58.30	38.30	75.01	75.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.18	0.00	0.00	0.00	17.15	18.25	0.00	0.00	0.00
2025	61.11	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.18	0.00	0.00	0.00	17.15	18.25	0.00	0.00	0.00
2026	63.46	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	63.46	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	63.46	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	63.46	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Exhibit No. 11a
TOTAL STRANDED COST CALCULATION

Net Present Value of Contribution Margins	$4,084,393
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	$1,000,500
Total Adjusted NPV excluding Negative Values	$5,395,886
Book Value	$6,688,384
Stranded Generation Cost	$1,292,498

Scenario: ICF FUEL PRICE Escalation

Exhibit No.___(RJF-11b)

Exhibit No. 11b

CALCULATION OF NET PRESENT VALUE OF CONTRIBUTION MARGINS

		==============Capacity==============				Capacity	Capacity	Energy	PSH								Net
	Year	Large Units	CT's	PSH	Total	Charges	Revenue	Margins	Magins	Total Costs	O&M	Cap. Add	A&G	Other Tax	Decomm.	Life Ext.	Margin
	1999	7462	835	880	9177	24.95	$228,984	$654,746	$8,534	$833,135	$505,885	$95,311	$49,177	$87,573	$26,425	$68,764	$59,129
	2000	7462	835	880	9177	38.59	$354,158	$722,214	$12,090	$781,284	$519,201	$97,684	$50,401	$87,573	$26,425	$0	$307,177
	2001	7462	835	880	9177	54.32	$498,459	$778,376	$15,419	$800,265	$533,739	$100,615	$51,913	$87,573	$26,425	$0	$491,989
	2002	7462	835	880	9177	52.07	$477,811	$835,035	$16,785	$819,774	$548,672	$103,633	$53,471	$87,573	$26,425	$0	$509,857
	2003	7462	835	880	9177	49.33	$452,679	$897,567	$18,944	$936,032	$571,987	$106,742	$55,075	$87,573	$26,425	$88,230	$433,158
	2004	7462	835	880	9177	54.60	$501,081	$909,589	$20,092	$902,147	$589,582	$109,944	$56,727	$87,573	$26,425	$31,895	$528,615
Disc. Rate	2005	7462	835	880	9177	58.17	$533,832	$937,606	$20,636	$894,221	$608,551	$113,243	$58,429	$87,573	$26,425	$0	$597,852
7.60%	2006	7462	835	880	9177	61.28	$562,327	$969,412	$20,867	$1,015,635	$627,369	$117,082	$60,410	$87,573	$26,425	$96,777	$536,972
	2007	7462	835	880	9177	59.46	$545,653	$1,037,179	$23,186	$946,028	$648,522	$121,051	$62,458	$87,573	$26,425	$0	$659,990
Tax Rate	2008	7462	835	880	9177	62.62	$574,679	$1,074,012	$23,981	$973,623	$669,896	$125,154	$64,575	$87,573	$26,425	$0	$699,049
41.49%	2009	7462	835	880	9177	65.59	$601,885	$1,114,887	$23,392	$1,002,521	$692,362	$129,397	$66,764	$87,573	$26,425	$0	$737,623
	2010	7462	835	880	9177	63.09	$579,018	$1,194,288	$25,848	$1,185,489	$710,916	$133,784	$69,027	$87,573	$26,425	$157,764	$813,661
	2011	7183	835	880	8898	65.95	$586,807	$1,200,218	$26,542	$1,022,564	$709,991	$135,798	$67,571	$82,779	$26,425	$0	$791,002
	2012	7183	835	880	8898	68.75	$611,733	$1,249,705	$26,530	$1,057,885	$738,073	$140,632	$69,977	$82,779	$26,425	$0	$830,083
Post 2014	2013	7183	835	880	8898	71.50	$636,211	$1,304,542	$26,239	$1,087,820	$763,858	$145,639	$72,488	$82,779	$23,077	$0	$879,172
Inflation	2014	6719	835	880	8434	74.08	$624,651	$1,250,051	$26,499	$1,169,265	$790,508	$150,824	$75,048	$82,779	$19,251	$50,878	$731,915
3.56%	2015	5638	0	880	6518	76.70	$499,931	$1,143,247	$27,442	$925,033	$669,132	$122,326	$55,360	$58,964	$19,251	$0	$745,587
	2016	5638	0	880	6518	79.43	$517,728	$1,183,947	$28,419	$952,080	$692,369	$126,680	$57,331	$58,964	$16,735	$0	$778,014
	2017	5167	0	880	6047	82.28	$497,418	$1,118,430	$29,431	$852,499	$597,408	$120,021	$59,372	$58,964	$16,735	$0	$790,777
	2018	5167	0	880	6047	85.19	$515,124	$1,156,175	$30,478	$879,570	$618,091	$124,294	$61,486	$58,964	$16,735	$0	$822,207
	2019	4811	0	880	5691	88.22	$502,058	$1,112,280	$31,563	$888,270	$625,754	$123,143	$63,675	$58,964	$16,735	$0	$757,629
	2020	4667	0	880	5547	91.36	$506,774	$1,120,821	$32,687	$880,479	$622,587	$124,389	$63,050	$56,378	$14,075	$0	$779,802
	2021	4198	0	880	5078	94.61	$480,252	$1,034,204	$33,851	$758,983	$507,265	$115,971	$65,294	$56,378	$14,075	$0	$789,324
	2022	3844	0	880	4724	97.98	$462,860	$967,171	$35,058	$736,407	$482,633	$115,702	$67,619	$56,378	$14,075	$0	$728,680
	2023	3844	0	880	4724	101.47	$479,338	$1,001,603	$36,304	$752,970	$499,231	$119,621	$70,026	$56,378	$7,514	$0	$764,275
	2024	3844	0	880	4724	105.08	$496,402	$1,037,260	$37,596	$776,917	$516,420	$124,087	$72,519	$56,378	$7,514	$0	$794,341
	2025	2689	0	880	3569	108.82	$388,385	$654,090	$38,935	$488,561	$329,040	$71,852	$44,984	$33,770	$8,916	$0	$592,848
	2026	1627	0	880	2507	112.70	$282,529	$536,381	$40,321	$398,117	$259,004	$65,120	$37,728	$27,349	$8,916	$0	$461,113
	2027	1627	0	880	2507	116.71	$292,587	$555,477	$41,756	$410,707	$267,933	$67,439	$39,071	$27,349	$8,916	$0	$479,113
	2028	1627	0	880	2507	120.86	$303,003	$575,252	$43,243	$423,745	$277,179	$69,839	$40,462	$27,349	$8,916	$0	$497,752
	2029	1627	0	880	2507	125.17	$313,790	$595,731	$44,782	$437,248	$286,755	$72,326	$41,902	$27,349	$8,916	$0	$517,055

NPV of Net Margins After Tax $4,084,393

Exhibit No.___(RJF-11c)

Pumped Storage

Exhibit No. 11c
PUMPED STORAGE UNITS
ECONOMIC BENEFITS AND OPERATIONS

YEAR	MW	BENEFIT	GEN MWH	CF	PUMPING COST	GEN. VALUE	DAYS	HOURS	LOSS FACTOR
1999	1693	16418630	2278778	15.4	15.64	29.41	239	1346	1.42
2000	1693	23259450	2774827	18.7	15.83	30.86	287	1639	1.42
2001	1693	29664580	3223472	21.7	16.58	32.74	303	1904	1.42
2002	1693	32291640	3318280	22.4	16.67	33.4	304	1960	1.42
2003	1693	36446580	3507896	23.7	16.92	34.41	309	2072	1.42
2004	1342	30639980	2836988	24.1	17.05	35.01	311	2114	1.42
2005	1342	31469480	2824910	24	17.3	35.71	312	2105	1.42
2006	1342	31822360	2836988	24.1	17.84	36.56	316	2114	1.42
2007	1342	35358270	2846382	24.2	18.4	38.55	314	2121	1.42
2008	1342	36571200	2908114	24.7	18.97	39.51	322	2167	1.42
2009	1342	35672460	2941664	25	19.51	39.84	328	2192	1.42
2010	1342	39415600	2975214	25.3	20.49	42.34	333	2217	1.42
2011	1342	40476220	2985950	25.4	21.46	44.02	342	2225	1.42
2012	1342	40458720	2985950	25.4	22.19	45.06	341	2225	1.42
2013	1342	40014630	2988634	25.4	22.94	45.96	343	2227	1.42
2014	1342	40410320	3024868	25.7	23.91	47.31	346	2254	1.42

Scenario: ICF FUEL PRICE Escalation

Exhibit No.___(RJF-11d)

Exhibit No. 11d

Large Units
Capacity mW

UNIT		Conowin 1	Limerk 2	Limerk 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2000	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2001	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2002	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2003	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2004	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2005	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2006	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2007	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2008	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2009	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2010	7462	512	1115	1155	464	464	471	471	176	176	178	178	302	279	144	201	380	380	126	124	166
2011	7183	512	1115	1155	464	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2012	7183	512	1115	1155	464	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2013	7183	512	1115	1155	464	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2014	6719	512	1115	1155	0	464	471	471	176	176	178	178	302	0	144	201	380	380	126	124	166
2015	5638	512	1115	1155	0	0	471	471	176	176	178	178	302	0	144	0	380	380	0	0	0
2016	5638	512	1115	1155	0	0	471	471	176	176	178	178	302	0	144	0	380	380	0	0	0
2017	5167	512	1115	1155	0	0	471	0	176	176	178	178	302	0	144	0	380	380	0	0	0
2018	5167	512	1115	1155	0	0	471	0	176	176	178	178	302	0	144	0	380	380	0	0	0
2019	4811	512	1115	1155	0	0	471	0	176	176	0	0	302	0	144	0	380	380	0	0	0
2020	4667	512	1115	1155	0	0	471	0	176	176	0	0	302	0	0	0	380	380	0	0	0
2021	4196	512	1115	1155	0	0	0	0	176	176	0	0	302	0	0	0	380	380	0	0	0
2022	3844	512	1115	1155	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2023	3844	512	1115	1155	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2024	3844	512	1115	1155	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2025	2689	512	1115	0	0	0	0	0	0	0	0	0	302	0	0	0	380	380	0	0	0
2026	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	1627	512	1115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Large Unit Output Report

UNIT		Conowin 1	Limerk 2	Limerk 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	38939	1718	7327	7590	3052	3052	2939	2937	1280	1277	1258	1237	1382	1277	803	405	570	539	212	148	140
2000	39465	1718	7327	7590	3052	3052	2940	2938	1280	1278	1264	1247	1501	1384	835	447	637	601	237	170	167
2001	39881	1718	7327	7590	3052	3052	2938	2937	1280	1279	1269	1255	1551	1445	688	480	704	659	281	190	180
2002	40121	1718	7327	7590	3052	3052	2938	2937	1281	1279	1272	1258	1582	1475	716	484	756	707	290	207	209
2003	40419	1718	7327	7590	3052	3052	2938	2938	1281	1280	1278	1264	1617	1511	737	519	813	767	301	227	232
2004	40279	1718	7327	7590	3052	3052	2938	2938	1281	1280	1277	1266	1635	1528	746	487	749	701	282	213	217
2005	40346	1718	7327	7590	3052	3052	2939	2939	1281	1280	1280	1271	1666	1561	767	437	721	676	272	205	213
2006	40247	1718	7327	7590	3052	3052	2940	2940	1282	1281	1283	1275	1697	1582	785	421	665	651	262	198	206
2007	40432	1718	7327	7590	3052	3052	2907	2937	1281	1280	1285	1277	1725	1620	802	430	710	660	268	203	212
2008	40437	1718	7327	7590	3052	3052	2907	2938	1281	1281	1287	1280	1754	1650	820	418	687	645	258	197	208
2009	40440	1718	7327	7590	3052	3052	2907	2939	1282	1281	1288	1283	1781	1677	836	403	688	629	251	191	200
2010	40673	1718	7327	7590	3052	3052	2907	2939	1282	1282	1290	1285	1808	1702	852	415	663	643	257	187	207
2011	38847	1718	7327	7590	3052	3052	2907	2940	1282	1282	1292	1288	1829	0	888	401	664	624	250	181	202
2012	38831	1718	7327	7590	3052	3052	2907	2941	1283	1283	1294	1290	1851	0	880	391	647	609	243	187	197
2013	38888	1718	7327	7590	3052	3052	2907	2907	1282	1282	1294	1290	1870	0	892	407	631	605	237	182	193
2014	35819	1718	7327	7590	0	3052	2907	2907	1282	1282	1295	1292	1888	0	904	397	617	580	232	178	188
2015	31770	1718	7327	7590	0	0	2907	2907	1282	1282	1295	1292	1889	0	904	0	617	580	0	0	0
2016	31770	1718	7327	7590	0	0	2907	2907	1282	1282	1295	1293	1888	0	904	0	617	580	0	0	0
2017	28773	1718	7327	7590	0	0	2907	0	1282	1282	1295	1292	1889	0	904	0	617	580	0	0	0
2018	28773	1718	7327	7590	0	0	2907	0	1282	1282	1295	1292	1889	0	904	0	617	580	0	0	0
2019	26106	1718	7327	7590	0	0	2907	0	1282	1282	0	0	1889	0	904	0	617	580	0	0	0
2020	25202	1718	7327	7590	0	0	2907	0	1282	1282	0	0	1889	0	0	0	617	580	0	0	0
2021	22295	1718	7327	7590	0	0	0	0	1282	1282	0	0	1889	0	0	0	617	580	0	0	0
2022	19721	1718	7327	7590	0	0	0	0	0	0	0	0	1889	0	0	0	617	580	0	0	0
2023	19721	1718	7327	7590	0	0	0	0	0	0	0	0	1889	0	0	0	617	580	0	0	0
2024	19721	1718	7327	7590	0	0	0	0	0	0	0	0	1889	0	0	0	617	580	0	0	0
2025	12131	1718	7327	0	0	0	0	0	0	0	0	0	1889	0	0	0	617	580	0	0	0
2026	9045	1718	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	9045	1718	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	9045	1718	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	9045	1718	7327	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fuel Cost $ (1000)

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	311371	17	32986	34106	15865	16044	22489	22689	14001	13967	16854	16802	21077	19693	9710	10310	15467	14854	5736	4532	4782
2000	323061	17	32383	33925	15781	15959	22384	22578	13870	13844	16786	16588	22083	21292	10129	11051	18151	17068	6488	6382	5817
2001	338295	17	32788	34318	15862	16142	22631	22829	13968	13948	16982	16783	23582	22219	11206	13637	20045	19798	7447	6343	6857
2002	350158	17	33143	34716	16149	16329	22982	23092	14089	14052	17142	16967	24224	22952	11581	14098	23448	22231	8295	7045	7829
2003	364239	17	33524	35109	16331	16510	23156	23380	14172	14158	17313	17158	24941	23568	12003	15726	26309	24575	8281	8058	9044
2004	365002	17	33909	35513	16519	16708	23423	23830	14274	14281	17457	17308	25398	24021	12270	15407	25245	23976	8031	7838	8803
2005	368426	17	34298	35921	16709	16898	23898	23907	14380	14389	17822	17487	26086	24692	12868	14419	25348	24078	9035	7845	8867
2006	378950	17	35630	37315	17358	17553	24622	24840	14873	14884	18016	17895	27087	25695	13237	14517	25523	24246	9102	7908	9051
2007	395488	17	37012	38762	18031	18235	26072	25785	14956	14951	18397	18788	28086	26677	13798	15443	27194	25872	9893	8472	9747
2008	408928	17	38449	40288	18730	18942	27083	26782	15263	15257	18802	18705	29133	27707	14382	15584	27462	26129	9783	8583	9880
2009	418803	17	39840	41829	19457	19877	28135	27837	15573	15588	18210	19124	30170	28727	14862	15771	27779	26438	9811	8878	10004
2010	438828	17	41498	43452	20212	20441	29228	28922	15889	15885	19821	19544	31207	29748	15544	16848	29718	28323	10587	8328	10818
2011	418858	17	42838	44968	20818	21154	30248	29840	16277	16274	20118	20050	32373	0	16181	17084	30147	29730	10749	8474	11001
2012	430708	17	44437	46338	21848	21892	31302	30898	16875	16873	20827	20588	33550	0	16845	17349	30825	29205	10817	8837	11209
2013	444912	17	45887	48162	22403	22856	32394	32684	17089	17088	21127	21073	34708	0	17480	18848	31151	29717	11103	9818	11439
2014	434895	17	47582	49843	0	23447	33525	33825	17484	17482	21654	21808	35807	0	18158	19208	31778	30321	11121	10028	11708
2015	372018	18	49321	51843	0	0	34728	35038	18101	18098	22421	22370	37188	0	18788	0	32818	31398	0	0	0
2016	385282	18	51077	53480	0	0	35982	36284	18745	18742	23219	23187	38512	0	19458	0	34081	32507	0	0	0
2017	381404	18	52895	55384	0	0	37243	0	19413	19409	24046	23891	39883	0	20151	0	35305	33885	0	0	0
2018	374268	20	54778	57356	0	0	38568	0	20104	20100	24902	24845	41303	0	20868	0	36582	34883	0	0	0
2019	338073	20	58728	59397	0	0	39941	0	20819	20818	0	0	42773	0	21611	0	37884	36104	0	0	0
2020	325857	21	58748	61512	0	0	41383	0	21580	21557	0	0	44208	0	0	0	38211	37389	0	0	0
2021	294418	22	60839	63702	0	0	0	0	22328	22324	0	0	45873	0	0	0	40807	38721	0	0	0
2022	258858	23	63005	65970	0	0	0	0	0	0	0	0	47508	0	0	0	42053	40089	0	0	0
2023	267884	24	65240	68318	0	0	0	0	0	0	0	0	49187	0	0	0	43550	41527	0	0	0
2024	277400	24	67571	70750	0	0	0	0	0	0	0	0	50948	0	0	0	45101	43005	0	0	0
2025	214008	25	69978	0	0	0	0	0	0	0	0	0	52783	0	0	0	46708	44538	0	0	0
2026	72494	26	72468	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	75074	27	75047	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	77747	28	77719	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	80515	29	80486	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fuel Cost $/mWh

UNIT		Conowin 1	Limeric 2	Limeric 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	8.00	0.01	4.44	4.49	5.20	5.28	7.66	7.73	10.94	10.94	13.42	13.42	15.25	15.42	16.10	25.48	27.14	27.58	27.08	31.84	34.10
2000	8.18	0.01	4.42	4.47	5.17	5.23	7.61	7.68	10.84	10.83	13.28	13.28	15.10	15.27	15.95	26.74	26.49	28.83	27.38	31.54	34.83
2001	8.48	0.01	4.47	4.82	5.23	5.29	7.70	7.77	10.91	10.91	13.38	13.38	15.21	15.38	16.05	27.88	29.75	30.18	28.53	32.86	36.09
2002	8.73	0.01	4.52	4.57	5.29	5.35	7.78	7.86	10.98	10.99	13.48	13.48	15.31	15.48	16.17	29.12	31.02	31.64	29.83	34.83	37.46
2003	9.01	0.01	4.58	4.63	5.35	5.41	7.88	7.95	11.06	11.06	13.57	13.57	15.42	15.60	16.29	30.36	32.36	32.83	30.77	35.46	38.98
2004	9.06	0.01	4.63	4.68	5.41	5.47	7.97	8.04	11.14	11.14	13.67	13.67	15.53	15.71	16.40	31.04	33.78	34.20	32.02	36.79	40.57
2005	9.15	0.01	4.68	4.73	5.47	5.54	8.06	8.13	11.23	11.23	13.77	13.78	15.63	15.82	16.52	33.00	35.10	36.67	33.22	38.27	42.10
2006	9.42	0.01	4.88	4.92	5.69	5.75	8.37	8.45	11.45	11.45	14.04	14.04	15.98	16.14	16.88	34.48	36.72	37.24	34.74	38.94	43.94
2007	9.78	0.01	5.05	5.11	5.81	5.87	8.70	8.78	11.68	11.68	14.32	14.32	16.28	16.47	17.20	35.91	38.30	38.89	36.17	41.73	45.88
2008	10.08	0.01	5.25	5.31	6.14	6.21	9.04	9.12	11.91	11.91	14.61	14.61	16.65	16.79	17.54	37.48	39.97	40.91	37.81	43.47	47.86
2009	10.38	0.01	5.45	5.51	6.38	6.45	9.38	9.47	12.15	12.15	14.90	14.91	16.94	17.13	17.88	39.13	41.71	42.38	39.48	45.42	50.02
2010	10.77	0.01	5.66	5.72	6.62	6.70	9.75	9.84	12.38	12.38	15.21	15.21	17.28	17.48	18.24	40.79	43.81	44.12	41.23	47.38	52.25
2011	10.78	0.01	5.88	5.92	6.85	6.93	10.08	10.18	12.70	12.69	15.57	15.57	17.70	0.00	18.70	42.80	45.40	46.08	43.00	48.80	54.48
2012	11.08	0.01	6.06	6.13	7.08	7.17	10.44	10.54	13.00	13.00	15.84	15.94	18.13	0.00	19.14	44.37	47.33	48.03	44.93	51.53	56.90
2013	11.44	0.01	6.28	6.35	7.34	7.42	10.81	10.85	13.31	13.31	16.33	16.34	18.58	0.00	19.61	46.31	49.37	50.11	46.85	53.93	59.27
2014	12.14	0.01	6.50	6.57	0.00	7.68	11.18	11.29	13.64	13.64	16.72	16.72	19.01	0.00	20.08	48.38	51.49	52.28	48.80	56.34	61.96
2015	11.71	0.01	6.73	6.80	0.00	0.00	11.58	11.68	14.12	14.12	17.31	17.31	19.68	0.00	20.78	0.00	53.35	54.12	0.00	0.00	0.00
2016	12.13	0.01	6.97	7.05	0.00	0.00	12.00	12.11	14.82	14.82	17.93	17.93	20.38	0.00	21.52	0.00	55.25	56.05	0.00	0.00	0.00
2017	12.88	0.01	7.22	7.30	0.00	0.00	12.43	0.00	15.14	15.14	18.57	18.57	21.11	0.00	22.29	0.00	57.22	58.08	0.00	0.00	0.00
2018	13.01	0.01	7.48	7.58	0.00	0.00	12.87	0.00	15.68	15.68	19.23	19.23	21.87	0.00	23.08	0.00	59.28	60.11	0.00	0.00	0.00
2019	12.83	0.01	7.74	7.83	0.00	0.00	13.33	0.00	16.24	16.24	0.00	0.00	22.64	0.00	23.91	0.00	61.37	62.25	0.00	0.00	0.00
2020	12.08	0.01	8.02	8.10	0.00	0.00	13.80	0.00	16.82	16.82	0.00	0.00	23.45	0.00	0.00	0.00	63.56	64.46	0.00	0.00	0.00
2021	13.21	0.01	8.30	8.39	0.00	0.00	0.00	0.00	17.42	17.41	0.00	0.00	24.28	0.00	0.00	0.00	65.81	66.78	0.00	0.00	0.00
2022	13.12	0.01	8.60	8.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.15	0.00	0.00	0.00	68.16	69.14	0.00	0.00	0.00
2023	13.56	0.01	8.91	9.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.04	0.00	0.00	0.00	70.58	71.60	0.00	0.00	0.00
2024	14.07	0.01	9.22	9.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.97	0.00	0.00	0.00	73.10	74.15	0.00	0.00	0.00
2025	17.84	0.01	9.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.93	0.00	0.00	0.00	75.70	76.79	0.00	0.00	0.00
2026	9.01	0.02	9.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	9.30	0.02	10.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	9.60	0.02	10.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	9.90	0.02	10.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Market Energy Prices $/MWh

UNIT		Conowin 1	Limerk 2	Limerk 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddystn 2	Eddystn 1	Cromby 1	Cromby 2	Eddystn 3	Eddystn 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	24.61	23.29	23.29	23.29	23.29	23.29	23.29	23.30	23.30	23.32	23.59	23.73	27.84	28.06	29.48	40.18	43.46	44.42	43.22	49.38	56.08
2000	25.82	24.81	24.81	24.81	24.81	24.81	24.80	24.81	24.83	24.84	25.08	25.22	28.75	29.16	31.22	42.28	45.74	47.08	45.38	51.38	58.08
2001	26.29	26.24	26.24	26.24	26.24	26.24	26.24	26.25	26.26	26.25	26.48	26.62	30.13	30.53	31.82	43.38	46.71	47.83	46.45	52.03	57.85
2002	26.81	27.08	27.07	27.07	27.07	27.07	27.07	27.07	27.07	27.08	27.81	28.04	31.04	32.07	33.38	46.25	48.27	48.44	49.00	53.27	58.92
2003	27.40	29.24	29.24	29.24	29.24	29.24	29.24	29.24	29.24	29.25	29.46	29.50	33.24	33.08	35.01	47.82	49.84	51.38	49.61	54.97	58.07
2004	27.80	29.84	29.84	29.84	29.84	29.84	29.85	29.84	29.85	29.85	29.88	29.88	33.52	33.83	35.23	49.83	53.37	53.57	51.75	56.82	62.87
2005	29.22	30.42	30.42	30.42	30.42	30.42	30.42	30.42	30.43	30.44	30.62	30.71	34.11	34.40	35.74	53.40	54.82	55.94	53.93	58.50	65.01
2006	30.07	31.44	31.44	31.44	31.44	31.44	31.44	31.44	31.44	31.45	31.61	31.70	34.94	35.31	36.52	56.04	57.29	58.88	56.81	62.35	68.15
2007	31.83	33.25	33.28	33.25	33.25	33.25	33.25	33.26	33.25	33.27	33.40	33.50	36.71	37.08	38.30	58.05	60.40	61.90	58.50	65.85	72.07
2008	32.68	34.41	34.42	34.42	34.41	34.41	34.41	34.42	34.42	34.42	34.55	34.64	37.80	38.03	39.18	61.82	63.29	64.75	62.40	68.78	75.25
2009	33.80	35.07	35.68	35.68	35.68	35.68	35.67	35.67	35.67	35.68	35.79	35.68	38.76	39.10	40.22	64.83	66.35	67.83	65.48	72.10	78.88
2010	34.68	37.61	37.62	37.62	37.61	37.61	37.61	37.82	37.61	37.80	37.94	38.01	40.85	41.20	42.29	68.38	70.04	71.70	69.18	76.00	83.40
2011	36.46	39.27	39.28	39.27	39.27	39.27	39.27	39.27	39.28	39.28	39.37	39.43	42.18	0.00	43.56	71.77	73.43	75.20	72.45	80.08	87.36
2012	37.73	40.82	40.82	40.82	40.82	40.82	40.81	40.82	40.81	40.81	40.89	40.86	43.54	0.00	44.89	75.11	76.93	78.83	76.07	83.81	91.73
2013	39.07	42.47	42.48	42.47	42.47	42.47	42.47	42.47	42.48	42.47	42.54	42.62	45.04	0.00	46.36	78.72	80.65	82.67	78.72	87.97	96.06
2014	40.68	44.23	44.24	44.24	0.00	44.23	44.23	44.23	44.25	44.24	44.30	44.35	46.67	0.00	47.95	80.56	84.50	86.73	83.50	92.30	100.87
2015	41.49	45.81	45.81	45.81	0.00	0.00	45.81	45.81	45.83	45.82	45.87	45.93	48.33	0.00	49.63	0.00	87.05	88.79	0.00	0.00	0.00
2016	42.97	47.45	47.45	47.45	0.00	0.00	47.44	47.44	47.46	47.45	47.51	47.58	50.05	0.00	51.39	0.00	90.77	92.88	0.00	0.00	0.00
2017	44.83	49.14	49.13	49.14	0.00	0.00	49.13	0.00	49.15	49.14	49.20	49.25	51.83	0.00	53.22	0.00	94.00	96.29	0.00	0.00	0.00
2018	46.24	50.88	50.88	50.88	0.00	0.00	50.88	0.00	50.90	50.89	50.95	51.01	53.68	0.00	55.12	0.00	97.35	99.72	0.00	0.00	0.00
2019	48.04	52.70	52.70	52.70	0.00	0.00	52.68	0.00	52.71	52.70	0.00	0.00	55.58	0.00	57.08	0.00	100.82	103.27	0.00	0.00	0.00
2020	49.88	54.57	54.57	54.57	0.00	0.00	54.58	0.00	54.59	54.58	0.00	0.00	57.57	0.00	0.00	0.00	104.41	106.95	0.00	0.00	0.00
2021	51.71	56.51	56.51	56.51	0.00	0.00	0.00	0.00	56.53	56.52	0.00	0.00	59.62	0.00	0.00	0.00	108.12	110.78	0.00	0.00	0.00
2022	53.65	58.53	58.53	58.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.74	0.00	0.00	0.00	111.97	114.70	0.00	0.00	0.00
2023	55.77	60.61	60.61	60.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.94	0.00	0.00	0.00	115.96	118.78	0.00	0.00	0.00
2024	57.75	62.77	62.77	62.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.22	0.00	0.00	0.00	120.09	123.01	0.00	0.00	0.00
2025	61.66	65.00	65.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	68.57	0.00	0.00	0.00	124.38	127.38	0.00	0.00	0.00
2026	58.98	67.32	67.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	61.08	69.71	69.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	63.25	72.19	72.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	65.50	74.78	74.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Market Energy Revenues ($1000)

UNIT		Conowin 1	Limerk 2	Limerk 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddystn 2	Eddystn 1	Cromby 1	Cromby 2	Eddystn 3	Eddystn 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.59	42.59	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2016	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	966117	40018	170081	170783	71083	71083	68458	68429	29826	29780	29628	29349	38201	35854	17770	18283	24770	23843	9182	7207	7851
2000	1045265	42815	181770	188291	75710	75710	72921	72902	31781	31744	31895	31449	43149	40849	19825	18886	29138	27839	10756	8734	8698
2001	1110871	45076	192280	198185	80083	80083	77108	77086	33809	33580	33619	33402	46738	44118	22208	21217	32884	31443	12124	9888	10881
2002	1185184	47525	202718	209989	84435	84435	81289	81277	35438	35412	35503	35299	50054	47304	23808	22383	36494	34851	13438	11027	12315
2003	1261808	50226	214238	221923	89234	89234	85813	85803	37458	37435	37580	37405	53751	50882	25800	24780	40517	38388	14904	12307	13888
2004	1274581	60010	217185	224986	90483	90483	87102	87083	37978	37957	38138	37858	54802	51881	28352	24285	38170	37558	14584	12123	13800
2005	1308032	52258	222905	230802	92844	92844	89410	89403	38987	38988	39194	39033	56834	53846	27408	23338	38382	37780	14870	12188	13848
2006	1348382	54010	230379	238644	95856	95858	92426	92421	40305	40290	40582	40415	58788	58217	28888	23581	39820	38193	14832	12348	14038
2007	1432867	57125	243083	252405	101490	101490	98847	97878	42590	42588	42815	42780	63327	60088	30715	25382	42828	41225	15871	13388	15278
2008	1480840	58120	252171	281218	105034	105034	103128	101112	44088	44067	44462	44342	68084	62742	32124	25717	43470	41784	16170	13549	15501
2009	1533070	61288	261422	270800	108887	108887	108808	104843	45728	45717	48137	46028	69030	65578	33828	26128	44188	42458	16438	13788	15788
2010	1631114	64958	277081	287022	115409	115408	113314	111138	48472	48485	48940	48841	73787	70124	38030	28248	47838	46029	17778	14888	17284
2011	1618878	67465	287709	298083	119880	119880	117685	115481	50358	50352	50888	50780	77080	0	37721	28778	48755	48827	18112	15298	17848
2012	1680413	70122	298104	308834	124582	124582	122320	120052	52381	52356	52918	52834	80582	0	39501	28387	49773	47838	18485	15838	18071
2013	1749454	72882	311218	322380	129828	129628	127273	127272	54453	54448	55049	54870	84232	0	41353	31227	50882	48028	18894	16011	18548
2014	1804848	75807	324120	333740		135001	132551	132550	56723	56720	57383	57297	88151	0	43344	31888	52183	50302	18371	16440	18083
2015	1518388	78718	335888	347735	0	0	137291	137291	58751	58742	59405	59337	91288	0	44882	0	54082	52878	0	0	0
2016	1888208	81612	347837	380115	0	0	142178	142178	60843	60833	61520	61449	94548	0	46450	0	58007	53830	0	0	0
2017	1477834	84414	380012	372835	0	0	147240	0	63008	62990	63710	63637	97814	0	48113	0	60001	55850	0	0	0
2018	1830444	87418	372828	388211	0	0	152481	0	65252	65241	65078	65003	101400	0	49828	0	62086	57838	0	0	0
2019	1448363	90531	388102	398901	0	0	157810	0	67575	67584	0	0	105018	0	51588	0	62204	59807	0	0	0
2020	1448478	93784	399847	414188	0	0	163531	0	69981	69969	0	0	108748	0	0	0	64418	62030	0	0	0
2021	1328820	97082	414081	428845	0	0	0	0	72472	72480	0	0	112820	0	0	0	66712	64238	0	0	0
2022	1225827	100548	428823	444215	0	0	0	0	0	0	0	0	116829	0	0	0	69087	66525	0	0	0
2023	1269487	104128	444088	460029	0	0	0	0	0	0	0	0	120761	0	0	0	71547	68863	0	0	0
2024	1314880	107835	458888	478408	0	0	0	0	0	0	0	0	125061	0	0	0	74094	71348	0	0	0
2025	988088	111874	478271	0	0	0	0	0	0	0	0	0	129534	0	0	0	76731	73888	0	0	0
2026	808875	115848	493228	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	630551	119788	510785	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	852998	124030	528888	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	876246	128446	547800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Energy Margins ($1000)

UNIT		Conesvln 1	Limerk 2	Limerk 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.50	42.50	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2018	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	654749	39883	138095	142077	55218	55039	45057	45740	15825	15813	12774	12747	17124	18161	8088	5853	8303	9089	3429	2878	3080
2000	722214	42580	149377	154380	58829	58751	50537	50328	17811	17800	14809	14881	20488	19357	8897	6947	10087	10733	4268	3372	3887
2001	778378	45058	158502	164850	64121	63941	54489	54257	19841	19832	16631	16809	23148	21891	11002	7580	11038	11647	4677	3842	4134
2002	835035	47508	169573	175279	68289	68107	58397	58185	21370	21380	18381	18332	25830	24452	12327	8287	13046	12720	5144	3982	4488
2003	887567	50200	180714	186814	72903	72718	62757	62543	23288	23277	20277	20248	28810	27284	13787	9043	14208	13843	5843	4337	4845
2004	898589	50802	183289	189473	73848	73758	63679	63463	23704	23698	20879	20850	29406	27989	14082	8858	13925	13574	5543	4287	4797
2005	937808	52241	188808	194881	76135	75948	65712	65486	24807	24800	21572	21548	30768	29154	14741	8917	14033	13882	5835	4363	4881
2006	988412	53983	194749	201329	78508	78403	67804	67581	25832	25828	22548	22520	32208	30522	15431	9074	14297	13944	5730	4437	4967
2007	1037179	57108	208851	213843	83458	83255	73578	71893	27841	27835	24518	24492	35241	33411	16819	9849	15731	15353	6278	4888	5631
2008	1074012	59103	213722	220852	88304	88082	78043	74320	28835	28830	25880	25837	36851	35035	17742	10123	16017	15836	6383	4989	5841
2009	1114887	61271	221482	229871	89430	89210	78774	77008	30153	30149	26927	26904	38890	36849	19066	10357	16407	16022	6525	5111	5794
2010	1184288	64842	235591	243579	95187	94989	84088	82217	32583	32580	29319	29297	42580	40379	20489	11400	18120	17709	7178	5989	6449
2011	1200218	67448	244831	253129	98842	98708	87439	85521	34081	34078	30751	30730	44717	0	21530	11894	18809	18189	7363	5821	6845
2012	1249705	70105	254867	263288	102934	102890	91018	89058	35688	35683	32288	32208	47042	0	22850	12018	19148	18721	7568	6089	6882
2013	1304542	72845	265228	274218	107223	108870	94878	94588	37384	37382	33922	33903	49523	0	23863	12378	19741	19306	7791	6186	7101
2014	1250051	75878	276528	285905	0	111554	99028	98725	38238	38238	35709	35681	52244	0	25188	12788	20423	19981	8050	6418	7374
2015	1143247	78882	286385	296083	0	0	102585	102255	40850	40844	36984	36987	54118	0	26073	0	21183	20888	0	0	0
2016	1183947	81494	296500	306835	0	0	108218	105894	42098	42091	38301	38282	56036	0	27001	0	21918	21423	0	0	0
2017	1118430	84395	307117	317551	0	0	109997	0	43580	43590	38884	39646	58031	0	27982	0	22880	22185	0	0	0
2018	1156175	87389	318051	328858	0	0	113813	0	45148	45141	41078	41058	60087	0	28958	0	23504	22975	0	0	0
2019	1112290	90511	329374	340584	0	0	117989	0	46756	46748	0	0	62237	0	29988	0	24340	23785	0	0	0
2020	1120821	93733	341099	352687	0	0	122159	0	48421	48412	0	0	64452	0	0	0	25208	24641	0	0	0
2021	1034204	97070	353242	365243	0	0	0	0	50144	50136	0	0	66747	0	0	0	26105	25517	0	0	0
2022	987171	100525	365818	378245	0	0	0	0	0	0	0	0	69123	0	0	0	27034	26426	0	0	0
2023	1001803	104104	378841	391711	0	0	0	0	0	0	0	0	71584	0	0	0	27997	27366	0	0	0
2024	1037290	107811	392327	405658	0	0	0	0	0	0	0	0	74132	0	0	0	28993	28341	0	0	0
2025	654090	111648	408295	0	0	0	0	0	0	0	0	0	76771	0	0	0	30025	29350	0	0	0
2026	536381	115623	420758	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	555477	119739	435738	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	575252	124002	451250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	595731	128417	467314	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Unit Capacity Factors

UNIT		Conesvln 1	Limerk 2	Limerk 1	Peach B 2	Peach B 3	Salem 2	Salem 1	Conemau 2	Conemau 1	Keyston 2	Keyston 1	Eddysto 2	Eddysto 1	Cromby 1	Cromby 2	Eddysto 3	Eddysto 4	Delawar 7	Delawar 8	Schuylk 1
Own %		100	100	100	42.49	42.49	42.50	42.50	20.72	20.72	20.99	20.99	100	100	100	100	100	100	100	100	100
Retire	Total	3000	3000	2024	2013	2014	2020	2018	2021	2021	2018	2018	2025	2010	2019	2014	2025	2025	2014	2014	2014
1999	59.57	38.30	75.01	75.02	75.09	75.09	71.23	71.18	83.02	82.83	80.55	79.33	52.24	52.75	47.80	23.00	17.12	18.18	18.21	13.44	9.63
2000	60.37	38.30	75.01	75.02	75.08	75.08	71.28	71.21	83.02	82.89	81.08	79.87	56.74	57.04	50.34	25.30	19.14	17.78	21.47	15.85	11.48
2001	61.01	38.30	75.01	75.02	75.09	75.09	71.21	71.18	83.02	82.98	81.38	80.48	58.83	58.12	55.33	27.77	21.15	18.71	23.85	17.48	13.07
2002	61.38	38.30	75.01	75.02	75.09	75.09	71.21	71.18	83.09	82.98	81.58	80.74	59.80	60.35	56.78	27.49	22.71	21.24	25.37	18.08	14.37
2003	61.83	38.30	75.01	75.02	75.09	75.09	71.21	71.21	83.09	83.02	81.83	81.06	61.12	61.82	58.43	29.42	24.42	22.44	27.27	20.98	15.85
2004	61.82	38.30	75.01	75.02	75.09	75.09	71.21	71.21	83.09	83.02	81.90	81.19	61.80	62.98	58.30	27.88	22.47	21.08	25.55	18.61	14.82
2005	61.57	38.30	75.01	75.02	75.09	75.09	71.23	71.23	83.09	83.02	82.09	81.51	62.97	63.07	60.80	24.82	21.88	20.28	24.84	18.67	14.65
2006	61.57	38.30	75.01	75.02	75.09	75.09	71.28	71.28	83.15	83.09	82.28	81.77	64.18	65.14	62.23	23.61	20.88	19.98	23.74	18.23	14.17
2007	61.65	38.30	75.01	75.02	75.09	75.09	72.84	71.18	83.09	83.02	82.41	81.90	65.20	66.28	63.58	24.42	21.33	20.01	24.28	18.88	14.58
2008	61.88	38.30	75.01	75.02	75.09	75.09	72.84	71.21	83.09	83.09	82.54	82.09	66.30	67.51	65.01	23.83	20.84	19.38	23.47	18.14	14.17
2009	61.87	38.30	75.01	75.02	75.09	75.09	72.84	71.23	83.15	83.09	82.67	82.28	67.32	68.62	66.27	22.88	20.01	18.78	22.74	17.58	13.75
2010	62.07	38.30	75.01	75.02	75.09	75.09	72.84	71.23	83.15	83.15	82.73	82.41	68.27	69.84	67.54	23.48	20.52	19.28	23.28	18.14	14.24
2011	61.74	38.30	75.01	75.02	75.09	75.09	72.84	71.28	83.15	83.15	82.86	82.60	69.14	0.00	68.65	22.77	19.95	18.75	22.65	17.38	13.88
2012	61.71	38.30	75.01	75.03	75.06	75.09	72.84	71.28	83.22	83.22	82.99	82.73	69.87	0.00	69.78	22.21	19.44	18.29	22.02	17.22	13.56
2013	61.80	38.30	75.01	75.02	75.09	75.09	72.84	72.84	83.15	83.15	82.99	82.73	70.09	0.00	70.71	23.12	18.88	17.81	21.47	16.78	13.27
2014	60.65	38.30	75.01	75.02	0.00	75.09	72.84	72.84	83.15	83.15	83.05	82.86	71.40	0.00	71.86	22.86	18.54	17.42	21.02	16.38	13.00
2015	64.33	38.30	75.01	75.02	0.00	0.00	72.84	72.84	83.15	83.15	83.05	82.86	71.40	0.00	71.86	0.00	18.54	17.42	0.00	0.00	0.00
2016	64.33	38.30	75.01	75.02	0.00	0.00	72.84	72.84	83.15	83.15	83.05	82.86	71.40	0.00	71.86	0.00	18.54	17.42	0.00	0.00	0.00
2017	63.87	38.30	75.01	75.02	0.00	0.00	72.84	0.00	83.15	83.15	83.05	82.86	71.40	0.00	71.86	0.00	18.54	17.42	0.00	0.00	0.00
2018	63.87	38.30	75.01	75.02	0.00	0.00	72.84	0.00	83.15	83.15	83.05	82.86	71.40	0.00	71.86	0.00	18.54	17.42	0.00	0.00	0.00
2019	62.13	38.30	75.01	75.02	0.00	0.00	72.84	0.00	83.15	83.15	0.00	0.00	71.40	0.00	71.86	0.00	18.54	17.42	0.00	0.00	0.00
2020	61.84	38.30	75.01	75.02	0.00	0.00	72.84	0.00	83.15	83.15	0.00	0.00	71.40	0.00	0.00	0.00	18.54	17.42	0.00	0.00	0.00
2021	60.63	38.30	75.01	75.02	0.00	0.00	0.00	0.00	83.15	83.15	0.00	0.00	71.40	0.00	0.00	0.00	18.54	17.42	0.00	0.00	0.00
2022	58.97	38.30	75.01	75.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.40	0.00	0.00	0.00	18.54	17.42	0.00	0.00	0.00
2023	58.57	38.30	75.01	75.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.40	0.00	0.00	0.00	18.54	17.42	0.00	0.00	0.00
2024	58.57	38.30	75.01	75.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.40	0.00	0.00	0.00	18.54	17.42	0.00	0.00	0.00
2025	61.50	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.40	0.00	0.00	0.00	18.54	17.42	0.00	0.00	0.00
2026	63.48	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	63.48	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	63.48	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	63.48	38.30	75.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00