BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY FOR ISSUANCE OF QUALIFIED RATE ORDER UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

VOLUME II

January 22, 1997

PECO Energy Company
Response to Filing Requirements

Schedule 0-1
Respondent: Thomas P. Hill, Jr.

Q. Provide a copy of any securitization filing submitted prior to the filing of the restructuring plan.

Response:
Attached is Part 2 of 2 of the Company's original filing for Securitization at Docket R-00973877.

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PECO STATEMENT NO. 4

R-00973953

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY

FOR ISSUANCE OF A QUALIFIED RATE ORDER

UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY

OF

J. BARRY MITCHELL

Regarding PECO Energy Company's Proposal For Issuance Of Transition Bonds And Use Of Proceeds

ERM

CONTENTS

DIRECT TESTIMONY OF J. BARRY MITCHELL

I. QUALIFICATIONS

Q. Please state your name and business address.

A. J. Barry Mitchell, 2301 Market Street, Philadelphia, Pennsylvania.

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

A. I am the Vice President of Finance and Treasurer of PECO Energy Company ("PECO Energy" or the "Company").

Q. What are your responsibilities as Vice President of Finance and Treasurer?

A. I am the corporate officer responsible for organizing and implementing the Company's long-term financing, including the issuance of all bonds and other debt instruments. I have responsibility for the Company's investor relations program, including production of the annual report and maintenance of relationships with the investment community, and oversee the Company's securities reporting obligations. I am also responsible for managing various trust investments, such as the Company's pension and nuclear decommissioning trusts. Finally, I am responsible for performing special studies and analyses for management and other departments and for directing the day-to-day management of the Company's treasury, payroll and insurance operations.

Q. What is your educational background?

A. I graduated in 1970 from Lehigh University with a Bachelor of Science Degree in Business Administration. In 1971, I was awarded a Masters Degree in Business Administration from Lehigh University. In 1987, I attended the Executive Program at the Colgate Darden Graduate School of Business Administration, University of Virginia, which covered a broad curriculum including managerial finance, executive decision-making and other topics.

Q. Please summarize your experience with the Company.

A. I have been employed at PECO Energy for more than 25 years. With the exception of a three-year assignment in Corporate Planning in the late-1970's, I have been a part of the Company's Finance Department during the entire period. I was elected to my current position as Vice President of Finance and Treasurer in September, 1994.

Q. Have you testified on other occasions before utility regulatory agencies?

A. Yes, I testified in the 1989 Limerick Generating Station Electric Rate Case (Docket R-891364) to describe the Company's need to reflect Limerick 2 and associated common plant in rates in order to earn an adequate rate of return. I testified on the Funding of SFAS 106 Costs (Docket R-00922479) to quantify the effect of adopting SFAS 106 and to provide a rationale for the Company's selection of vehicles in which to fund the cost of postretirement benefits other than pensions. I testified in the FERC Open Access Transmission Tariff (#ER96-641-000) to provide the basis for the Company's return on equity used in calculating its rates.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony has three objectives, all of which relate to the issuance of the new form of debt known as "Transition Bonds" created by the Electricity Generation Customer Choice and Competition Act (the "Competition Act"):

First, I will provide an overview of the concept of "securitization," both as generally used and as applied to electric utility transition or stranded costs by the Competition Act.

Second, I will describe the amount of the Transition Bonds; the amount and basis for the Qualified Transition Expenses to be recovered through the issuance of the Transition Bonds; and the uses of the proceeds of the sale of the Intangible Transition Property and its related revenue stream, the Intangible Transition Charges, funded by the Transition Bonds, including the estimated expenses of issuance of the Transition Bonds and the estimated costs associated with using the proceeds.

Third, I will describe PECO Energy's proposal for issuance of Transition Bonds; the financing structure and relationship of the entities and transactions involved; the true-up mechanism and other methods of credit enhancement; and PECO Energy's proposed timetable for issuance of the Transition Bonds.

III. OVERVIEW OF SECURITIZATION

Q. What is securitization?

A. "Securitization" means 1) taking certain legal and credit enhancement measures to segregate an identifiable asset from the general property of the seller, or original owner of the asset, and to decrease the risk to the investors that the asset and its related revenue stream will become uncollectible and 2) using the asset and its related revenue stream to secure a debt issuance which is used to fund the acquisition of the asset. In other words, the revenue stream associated with the asset is made more creditworthy than a normal business revenue stream and, as a result, the "securitized debt" supported by that revenue stream has less risk associated with it than typical corporate debt.

There are numerous methods of creating this higher degree of creditworthiness for an asset and its related revenue stream, but generally these methods fall into two categories. First, steps are taken to isolate the asset and its revenue stream from the credit risks of the original owner of the asset, such as the risk that the owner will go bankrupt. When this separation of risk is successfully achieved, investors look primarily to the asset's revenue stream for payment of interest and principal on the securitized debt, rather than relying on the credit of the original owner of the asset. I will discuss how this first category of increased creditworthiness will be achieved for the PECO Energy transaction in Section V of my testimony dealing with the structure proposed by PECO Energy for the issuance of Transition Bonds.

Second, the revenue stream itself may be the subject of credit enhancement mechanisms, such as "true-ups," overcollateralization or bond insurance, in order to achieve a cost-effective credit rating. I will discuss credit enhancement in Section VI of my testimony. The aim of all of these mechanisms is to give potential investors comfort that a creditworthy revenue stream will exist to pay the interest and principal on the securitized debt, so that the investors will be willing to purchase that debt at an interest rate lower than that of the original owner's corporate debt.

Q. **You stated that one of the primary methods of increasing the creditworthiness of the revenue stream is to isolate it from the credit risks of the original owner of those assets. How is that typically achieved?**

A. The asset and its associated revenue stream are sold in a transaction that qualifies as a sale for accounting and bankruptcy purposes to a "bankruptcy-remote" special purpose entity ("SPE") whose only business purpose is to own the asset, sell the securitized debt and receive the revenue stream on behalf of the investors.

Q. **What do you mean by "bankruptcy-remote"?**

A. In this context, being "bankruptcy-remote" refers to the fact that the credit of the SPE is not linked to that of the original owner of the asset, and it is unlikely that, in the event of a bankruptcy of the original owner, the SPE's assets will be subject to the claims of creditors of the original owner.

Q. You stated above that the second method of increasing the creditworthiness of the securitized debt is through "credit enhancement." Please explain what you mean by "credit enhancement" and give a few examples.

A. Credit enhancement is a mechanism that provides investors with assurance that they will recover their investment and a return thereon (interest). This assurance is provided through making available to investors additional amounts or sources of payment. Credit enhancement mechanisms fall into two basic categories: those provided by the original owner of the asset by the transaction structure, generally by enhancing the amount or nature of the revenue stream, and those provided by third parties. Examples of credit enhancement provided by the original owner include limited recourse, reserve accounts and overcollateralization. Examples of credit enhancement provided by third parties include bond insurance and letters of credit.

The Puget Sound Power & Light Company ("Puget") transaction I refer to throughout my testimony used both a "true-up" mechanism similar to that provided in the Competition Act and overcollateralization as credit enhancement. In the Puget transaction, the periodic true-ups provided assurance that the revenue stream would satisfy the obligations to the bondholders for the entire term of the bonds, except for the time between the last true-up and the final payment on the bonds. As a result, the actual amount of the overcollateralization (as presented in

Mr. Hiller's testimony) was based not on the original principal amount of the bonds issued, but on the amount outstanding at the time of the last true-up.

Q. What are some examples of securitized debt?

A. The most commonly securitized assets are credit card receivables and auto loans. In these transactions, the assets are often sold to an SPE, which then issues securities based on the creditworthiness of the assets. In some cases for tax, accounting or bankruptcy-related reasons, the assets are first transferred to a bankruptcy-remote, limited-purpose, wholly owned subsidiary of the original owner before being sold to the issuing SPE. In an auto loan securitization, the original owner (for example, Ford Credit) sells a diversified portfolio of auto loans to a trust, which is one of the forms of an SPE used in securitization transactions. The trust then issues certificates, evidencing undivided interests in the trust, to investors. As consumers repay their auto loans, this cash is collected by Ford Credit, as servicer, remitted to the trust and paid to investors in the form of interest and principal until the certificates are fully amortized. The cashflow, or the revenue stream associated with the payments on the auto loans sold to the trust, is the primary source of payment on the certificates and, to the extent consumers default on their loans, investors have no general claim against Ford Credit. In other words, Ford Credit has no obligation to make investors whole if the payments on the auto loans held by the trust are insufficient to cover debt service on the certificates. Thus, the creditworthiness of the securitization is based on the credit quality of the diversified auto loan portfolio sold to the trust, in addition to any credit enhancement included in the transaction, and is not related to the credit of Ford Credit.

Mr. Hiller's testimony provides further examples of securitization in the current marketplace, including the 1995 issuance of securitized debt related to Puget's energy conservation expenditures.

Q. How will the principles of securitization be applied to transition or stranded costs under the Competition Act?

A. The Pennsylvania General Assembly determined that it is in the public interest to use the securitization mechanism as a form of stranded investment mitigation and to reduce customer rates. As noted above, the first step in securitization is to identify an asset and its related revenue stream and isolate them from the other assets of the original owner, making them more creditworthy. In this case, the asset and its related revenue stream to be isolated are the Company's Intangible Transition Property ("ITP") and the related Intangible Transition Charges ("ITC") created under the Competition Act by the Commission's issuance of a Qualified Rate Order ("QRO"). The ITP represents the right to recover, through the ITC, Qualified Transition Expenses ("QTE"), consisting of the Company's stranded or transition costs, the expenses associated with issuing the Transition Bonds and the costs associated with the recapitalization, plus the costs to be incurred to credit enhance and to service the Transition Bonds. The ITP and the ITC are isolated from the risks of PECO Energy through their sale to an SPE.

The second step is to fund the SPE's purchase of the ITP and the ITC through the issuance of Transition Bonds. Under the Competition Act, the ITP and its related ITC revenue stream are made more creditworthy because the Commission has issued a QRO: 1) specifying the amount of QTE that can be recovered through the ITC, 2) approving the methodology for periodic true-ups of the ITC and 3) declaring the QRO irrevocable. Under the Competition Act, the Commonwealth has also agreed not to reduce the value of the ITP or the ITC until the Transition Bonds are discharged.

IV. AMOUNT OF TRANSITION BONDS TO BE ISSUED AND PECO ENERGY'S USE OF PROCEEDS

Q. Please provide a brief overview of the issues you will discuss in this section of your testimony.

A. I will discuss the amount and basis of the Qualified Transition Expenses for which PECO Energy is requesting approval for Transition Bonds issuance and PECO Energy's proposed uses of proceeds from the sale of the ITP and the related ITC funded by the Transition Bonds.

Q. What are Qualified Transition Expenses?

A. Qualified Transition Expenses are a set of expenditures, plus the costs to be incurred to credit enhance and to service the Transition Bonds, which an electric utility may use as the basis to request Commission approval for the issuance of Transition Bonds. Although the term is defined in detail in Section 2812(G) of the Competition Act, for purposes of my testimony I will simply note that three types of expenses in addition to the costs incurred to credit enhance and to service the Transition Bonds meet the definition of Qualified Transition Expenses: 1) a utility's transition or stranded costs, 2) the financing expenses associated with the issuance of Transition Bonds and 3) the costs associated with using the proceeds of the sale of the ITP and the related ITC, which include the cost of call and tender premiums to retire existing securities.

Q. What amount of Transition Bond issuance is PECO Energy requesting in its Application for a Qualified Rate Order?

A. PECO Energy is requesting approval for the issuance of Transition Bonds in the aggregate principal amount of approximately \$3.877 billion. This amount will return to PECO Energy proceeds sufficient to recover \$3.6 billion of transition or stranded costs, estimated issuance expenses of \$23.8 million and estimated costs associated with using the proceeds of \$253.5 million. The testimonies of Mr. Hill and Mr. Cohn support the transition or stranded costs of \$3.6 billion. My testimony will present the estimated expenses of issuing the Transition Bonds and the estimated costs of using the proceeds.

Q. What expenses do you estimate will be associated with issuing the Transition Bonds?

A. PECO Energy estimates that the expenses associated with the issuance of approximately \$3.877 billion of Transition Bonds to be approximately \$23.8 million. A detailed breakdown of this estimate is provided in Exhibit JBM-1. This estimated expense breakdown includes underwriter fees and expenses, legal fees and disbursements for outside finance counsel and underwriters' counsel, rating agency fees, accounting services, trustee fees, printing and other miscellaneous costs. These expenses can only be provided as estimates because the actual expenses will not be known until the QRO has been issued by the Commission and the Transition Bonds have been issued.

Because some of the information provided in Exhibit JBM-1 contains confidential proprietary data of entities that are not a party to this proceeding, including estimated underwriting fees, the detailed estimate has been provided only to the

Commission, but will be provided to other parties subject to a confidentiality requirement.

Q. Please describe how PECO Energy will use the proceeds from the sale of the ITP and its related ITC funded by the Transition Bonds.

A. PECO Energy has requested Commission approval for the issuance of Transition Bonds in an amount that will generate approximately $3.877 billion in proceeds. Section 2812(B)(2) of the Competition Act requires that proceeds of the sale of ITP and its related ITC be used "principally to reduce the electric utility's transition or stranded costs and to reduce the related capitalization."

The level of savings to customers resulting from the issuance of this amount of Transition Bonds is dependent primarily upon the interest rates of the Transition Bonds. *The calculation of these savings is presented in Mr. Cohn's testimony.* Although it is assumed that the Transition Bonds will be issued with a AAA rating at interest rates lower than the assumed interest rate on the Company's mortgage bonds, the primary determinant of the customer savings is the fact that the Company's balance sheet - comprised of debt and equity capital - is being reduced by proceeds from the sale of the ITP and the related ITC financed exclusively by debt.

PECO Energy will apply a total of approximately $277.3 million of proceeds to pay expenses of issuance of the Transition Bonds and costs associated with using the proceeds. The Company will earmark a total of $239 million for the deferred fuel costs described in Mr. Cohn's testimony.

PECO Energy will use the remaining proceeds of approximately $3.361 billion principally to reduce the Company's capitalization – in effect, to shrink its balance sheet. This capitalization reduction will occur for debt, preferred stock and common equity in amounts that are essentially proportionate to the Company's current debt and equity percentages, or approximately 50% debt, 5% preferred stock and 45% common equity. For purposes of these calculations, debt includes capital lease obligations and significant off-balance sheet debt obligations.

If the Transition Bonds are issued in more than one series, the proceeds will come in over time. PECO Energy will apply specific amounts of the proceeds it receives over time to certain of the uses I describe, depending on conditions existing at the time the proceeds are received. For the purpose of this testimony, I have described how the total proceeds will be applied in the aggregate; however, as the proceeds become available over time, PECO Energy may apply them to one or more uses on a case-by-case basis.

In addition, because PECO Energy is a publicly traded company, public announcement of the precise steps that will be taken to reduce capitalization could affect market behavior and the market price of its securities. For example, announcement of a common stock repurchase program would be expected to cause an increase in the Company's common stock price, resulting in fewer shares being bought back for any given amount of money. For this and other reasons, the Company's capital reduction plans must be coordinated with applicable SEC and New York Stock Exchange regulations. Within those constraints, the Company has reviewed the options available to it, including retiring debt and preferred stock and buying back common stock, and is able to provide the following information.

The Company's capital structure as calculated by rating agency methodology includes approximately 50% debt, including more than $4.5 billion of long-term and short-term debt. Therefore, approximately $1.7 billion of the total proceeds, net of issuance expenses and use of proceeds costs, (50% of the amount remaining after settlement of deferred fuel balances) will be used to reduce debt capitalization. PECO Energy has more than $600 million of long-term first mortgage bonds that are currently callable or that will become callable in 1997; approximately $850 million of long-term first mortgage bonds will be callable in 1998. (A full schedule of PECO Energy's outstanding debt and capital stock is provided as Exhibit JBM-2). In addition, PECO Energy may use tender offers, open market purchases or defeasance to retire non-callable debt.

The final decision of which of these options to pursue will depend, in large part, on the date on which the proceeds become available to the Company, the prevailing interest rates at that time and the requirements of the rating agencies. For example, if the proceeds of the Transition Bonds become available to the Company prior to a specific call date, then a tender offer, rather than a call, may be the most effective use of the proceeds. Similarly, if at the time the proceeds become available, the prevailing interest rates are higher than current levels, it may be beneficial to make a tender offer for higher-cost debt rather than to call lower-cost debt.

All of these factors will be fully evaluated in determining which of the options outlined above to pursue, once the proceeds become available for use. At that time, or at such time that market conditions and interest rate levels, rating agency requirements, securities regulations and other factors allow, the Company will inform the Commission which of the specific actions have been chosen.

The remaining $1.7 billion of proceeds is related to the equity capitalization of the Company (both common and preferred). The considerations for retiring preferred stock are essentially the same as those for long-term debt. The considerations for reduction of the Company's common equity are substantially different because PECO Energy's common stock is not callable and its price is affected by a number of factors, such as the interest rate environment and the prospects of the Company, including anticipated earnings and dividends. Sale of the ITP and related ITC to the SPE required for the issuance of the Transition Bonds will reduce the revenues, and consequently the earnings, of PECO Energy. In order for PECO Energy to continue to provide the holders of its common stock an adequate return on their investment, PECO Energy will have to reduce its common shareholder equity. This will be accomplished through stock buyback programs, such as open market purchases, tender offers or privately negotiated purchases, or dividends to the investors.

Equity markets are even more sensitive than the debt market to public announcements of a company's financial plans and PECO Energy therefore cannot state with specificity which of the above options it will choose. Finally, prevailing market conditions at the time the proceeds become available, such as the price of PECO Energy's common stock, will affect the decision of which of these options to use at any given time. As noted above, the Company will provide this information to the Commission, consistent with SEC and New York Stock Exchange regulations, when it uses the proceeds as they become available or such time as conditions allow.

In sum, PECO Energy commits that it will use the estimated $3.877 billion proceeds of the sale of the ITP and related ITC, net of issuance and use of proceed costs, as follows: $239 million will be applied to deferred fuel accounts; at least $1.7 billion will be used to retire existing debt through calls, open market purchases, tender offers and/or defeasance; approximately $0.17 billion will be used to retire existing preferred stock through redemption and/or tender offers; and the balance of approximately $1.5 billion will be used for shareholder purposes, including return of investment to shareholders through stock buybacks or dividends.

Q. What costs do you estimate will be associated with PECO Energy using the proceeds?

A. PECO Energy estimates that the costs associated with applying the proceeds it receives will be approximately $253.5 million. As described above, it is not possible at this time to determine the precise use of proceeds or the costs associated with their use, because the precise plan for use of proceeds and the associated costs are dependent on the market conditions at the time the proceeds become available for use by the Company. Nevertheless, PECO Energy is making the commitment to use the proceeds to retire existing debt in the principal amount of $1.7 billion. We estimate that the costs associated with retiring $1.7 billion of outstanding debt would be approximately $41.8 million. PECO Energy is also making the commitment to use an additional $1.7 billion of the proceeds to retire preferred stock and reduce common equity. We estimate that the costs associated with retiring preferred stock and reducing common equity would be approximately $7.6 million and $204.1 million, respectively. These costs are described in detail in Exhibit JBM-3.

Because of the market sensitive nature of the estimates included in Exhibit JBM-3, this exhibit has been provided only to the Commission, but will be provided to other parties subject to a confidentiality requirement

Q. If the amount of expenses associated with issuing the Transition Bonds and the costs associated with using the proceeds will not be known when the Commission issues its Qualified Rate Order, how will the Company reconcile its estimate of costs against actual costs?

A. As previously discussed, the Competition Act provides for the issuance of Transition Bonds to recover the Company's QTE. Therefore, the Company is requesting that the amount of estimated costs, totaling $277.3 million, be included in the QTE. The Company will establish a tracking account including an interest component for these costs, and reconcile any over- or under-collections with customers.

In order to maintain the bankruptcy-remoteness of the ITP and the ITC revenue stream, PECO Energy cannot have any interest in the ITP or the ITC revenue stream once they have been sold, assigned or transferred to the SPE. The expense reconciliation thus must occur in a tracking account that is separate and distinct from the ITP and the ITC. The reconciliation of costs will be a matter between PECO Energy and its customers, not the Transition Bondholders. They will have purchased the Transition Bonds for a set amount of money and will be entitled to recover that amount, plus interest, regardless of how the proceeds received by PECO Energy are used. Therefore, PECO Energy will track the actual costs in its separate tracking account and, once the actual level of expenses is known, inform the Commission of any reconciliation that is required. PECO Energy will then provide that reconciliation through a portion of its rates unrelated to the ITC.

V. PECO ENERGY'S PREFERRED STRUCTURE FOR THE ISSUANCE OF TRANSITION BONDS

Q. Please describe the proposed PECO Energy transaction.

A. PECO Energy's preferred structure will have the following general elements: 1) The Company will directly or indirectly sell the ITP and related ITC to one or more bankruptcy-remote SPEs established for the transaction (probably a trust). The sole purpose of the SPEs will be to buy the ITP and related ITC from PECO Energy, issue the Transition Bonds, receive the ITC revenues and pay interest and principal to the Transition Bondholders. The sale of the ITP and the related ITC revenue stream to the SPE will be structured as a "true sale" for bankruptcy purposes. 2) For accounting purposes, PECO Energy will record the transfer on its books and records as a sale. The obligation incurred by the SPE for the Transition Bonds will not be recorded as a liability of PECO Energy, but will be an obligation solely of the SPE. 3) For Federal income tax purposes, PECO Energy will report the transfer of the ITP and related ITC revenue stream as a debt financing, not a sale. As a result, PECO Energy will not face an immediate tax burden from the transaction. While this is PECO Energy's preferred transaction structure, each element is subject to change due to circumstances outside PECO Energy's direct control, which circumstances are discussed below.

The SPE will finance its acquisition of the ITP by issuing Transition Bonds, the proceeds of which will be remitted to PECO Energy as the purchase price of the ITP. The SPE may make certain deposits in reserve accounts or other facilities that may be created to provide the necessary credit enhancement to service the debt to achieve the desired rating for the Transition Bonds.

The final form of the Transition Bonds (whether they will be designated as notes, certificates or another form in accordance with the Competition Act) and the terms of the Transition Bonds will be determined at the time the Transition Bonds are marketed and after input from the rating agencies and PECO Energy's underwriters. PECO Energy also expects, subject to market conditions, that the Transition Bonds will be issued in more than one series, each of which may be in a different form and have different terms. As PECO Energy has done with its own financing program, it would like to maintain the flexibility to determine the form of the Transition Bonds, the amount to be offered at any particular time and the terms of the Transition Bonds at the time of each offering of Transition Bonds in light of the then-current market conditions. Accordingly, PECO Energy is requesting Commission approval of the issuance of approximately $3.877 billion principal amount of Transition Bonds with the form and terms of each series of the Transition Bonds to be determined at the time of offering. PECO Energy will notify the Commission upon consummation of the offering of each series of Transition Bonds of the specific terms of the offering.

PECO Energy will act as "servicer" of the ITC revenue stream and, in this capacity, the SPE will rely on PECO Energy to bill customers and make collections. In this role, PECO Energy will also initiate and participate in periodic "true-up" reviews of the ITC by the Commission in order to maintain the ITC at a level that allows full recovery of QTE, including the payment of interest and principal on the Transition Bonds, pursuant to the amortization schedule for the Transition Bonds determined at the time of offering. Pursuant to an agreement between PECO Energy and the SPE on behalf of Transition Bondholders, PECO Energy will collect the ITC and deposit the collections into accounts set up by the SPE for the Transition Bondholders, on a regularly scheduled basis determined in part by the rating agencies. These collection activities will be subject to the Commission's regulations regarding collections, customer relationships and other consumer-related matters. Within that framework, PECO Energy will follow instructions and perform these activities just as if it were a third-party contractor. As is typical in securitization transactions, the servicer will be paid an arm's length fee for the administration costs of servicing the ITC revenue stream.

Q. You referred to this structure as PECO Energy's "preferred" structure. Please explain.

A. There is some uncertainty on certain technical aspects which may impact the preferred structure, including accounting and tax treatments, as well as structural modifications which may be required to address legal and rating agency concerns. We believe that those uncertainties will be resolved in a manner that allows the Company to use its preferred structure; however, if those uncertainties are resolved other than as PECO Energy expects, certain structural modifications to PECO Energy's "preferred" structure will be required.

Q. What are the accounting uncertainties to which you refer?

A. PECO Energy would prefer to record this transaction as a sale for accounting purposes under SFAS 125, resulting in off-balance sheet treatment. Doing so would present the financial information regarding PECO Energy's recapitalization in the clearest form possible. As Mr. Gillen discusses in his testimony, Coopers & Lybrand, PECO Energy's independent accountant, has completed its review of both the proposed transaction structure and SFAS 125 and has determined that it is likely that PECO Energy will be able to record this transaction as a sale; however, because the accounting rules on this issue have not yet been tested through a series of real-world transactions, there is still some possibility that PECO Energy will be required to record this transaction as a financing for accounting purposes, resulting in on-balance sheet treatment.

If the transaction is considered to be on-balance sheet, then it is likely that PECO Energy will cause the Transition Bonds to be issued through a specially created PECO Energy finance subsidiary rather than the SPE trust structure. Although the on-balance sheet accounting treatment will not show as clearly the Company's recapitalization (because the Transition Bonds will be recorded as a liability of the finance subsidiary and be included in the consolidated debt of the Company), we believe that, due to the fundamental structure of the Transition Bond issuance, the rating agencies would "look through" the accounting treatment and treat the transaction in the same manner as if it had been recorded as a sale for book purposes.

Q. **What are the tax uncertainties to which you refer?**

A. PECO Energy proposes to characterize the transaction for Federal income tax purposes as a debt financing, rather than as a sale. That characterization will not cause the Company to recognize income or gain or loss from the sale of the ITP. As Mr. Gillen discusses in his testimony, we are in the process of applying to the Internal Revenue Service ("IRS") for a letter ruling seeking confirmation of the characterization of the transaction as a debt financing for Federal tax purposes.

Q. **What is the process for obtaining this letter ruling from the IRS?**

A. Outside counsel is drafting the ruling request. We plan to submit the request to the Ruling Branch of the IRS National Office within the next few weeks. At this point it is unclear how quickly the IRS will respond given the complexity of the issues involved and large amounts of potential tax liability. Nor is it clear whether the IRS will rule favorably on this issue, or even whether it will rule at all. If the IRS is unable to meet our current schedule for issuing Transition Bonds at the end of June, we may withdraw the request and rely on the opinion of our tax counsel or use the finance subsidiary structure described above. It should be noted that in the bulk of the securitization market, including the Puget transaction, the original owner of the asset has relied on opinions and advice from tax counsel, as opposed to revenue rulings, for the tax characterization of the transaction.

Q. In the event that resolution of either the accounting or tax issues requires you to use a finance subsidiary, what additional protections would need to be incorporated into the structure to achieve bankruptcy remoteness?

A. In the event PECO Energy uses the finance subsidiary structure, the transaction will be structured to take into account the same bankruptcy law considerations that govern the establishment of the bankruptcy-remote SPE in the preferred transaction structure. The SPE will have a separate legal existence, will be governed by a separate board of directors or trustees (including at least one independent director or trustee) and will have limited purposes so that it is unlikely to have creditors other than the Transition Bondholders.

Q. Would any of the potential changes described above affect the benefits of issuing Transition Bonds?

A. Although PECO Energy believes that greater savings may be achieved through its preferred structure because this structure will be more favorably received by the market, there would still be substantial benefits from any structure reflecting the above-mentioned changes. In each case, the same amount of Transition Bonds would be issued. PECO Energy would receive favorable tax treatment for the transaction and rate savings would be passed on to customers.

Q. Besides the Qualified Rate Order and the IRS ruling, are there any other regulatory or other approvals or filings PECO Energy needs to proceed?

A. The sale of the ITP and related ITC to the SPE in connection with the issuance of the Transition Bonds will require the release of that property from the lien of the Company's Mortgage (although the release will not actually occur until the Transition Bonds are issued). In addition, we will file a registration statement with the Securities and Exchange Commission in connection with any public offering of the Transition Bonds.

VI. TRUE-UP OF THE ITC AND OTHER CREDIT ENHANCEMENT MECHANISMS

Q. How does the structure of the ITC affect the pricing of the Transition Bonds?

A. On behalf of Transition Bondholders, PECO Energy will levy an ITC on customers in an amount sufficient to fully recover the Qualified Transition Expenses and directly or indirectly sell the rights to the ITP and the related ITC revenue stream to the SPE in the securitization transaction. As PECO Energy, acting as servicer, makes collections of the ITC, cash will be passed through the SPE to Transition Bondholders. Because Transition Bondholders will look primarily to the cashflows associated with the ITC, the forecasted ability of the ITC collections to meet the debt service of the Transition Bonds is the most important factor in determining the creditworthiness and, as a result, the pricing of the Transition Bonds.

The rating agencies will focus their analyses on factors which could potentially reduce ITC collections and how these factors are addressed by the transaction structure. ITC collections will likely be dependent on, among other things, PECO Energy's ability to forecast by customer class: 1) number of customers and/or usage; 2) delinquencies and charge-offs and 3) payment lags. As a result, the rating agencies will study, among other things, the historical number, usage patterns and payment patterns of PECO Energy's customers, the volatility of these factors over time and PECO Energy's ability to forecast these factors and trends in these factors. While rating agencies may have a high degree of comfort in a utility's ability to forecast customer characteristics, there can always be unforeseen occurrences which may cause actual results to deviate from these forecasts (e.g., weather patterns, economic conditions). As a result, the rating agencies are expected to require some form of credit enhancement to provide investors with the certainty of repayment commensurate with the rating of the Transition Bonds.

One form of credit enhancement will be the ability of PECO Energy to periodically "true-up" the ITC through application to the Commission as provided in the

Competition Act. To the extent ITC collections have proven insufficient (or more than sufficient) to amortize the QTE principal balance according to its amortization schedule, the Competition Act provides for periodic adjustments to the ITC. Through the adjustment mechanism discussed in Mr. Xander's testimony, PECO Energy will adjust the ITC to be billed in the future to account for any previous under- or over-collections (as well as any changes to PECO Energy's forecasts with regard to customers, usage, charge-offs, etc.), thereby making up for any of the uncertainties mentioned above and providing investors with certainty with regard to the ability to recover interest and principal on the Transition Bonds on schedule through the ITC.

In addition to the true-up mechanism, some other form of credit enhancement may be employed to address shortfalls occurring during the period after the final true-up until the Transition Bonds are discharged. One such option, which is addressed in Mr. Hiller's testimony and earlier in my testimony, is overcollateralization. The Puget transaction relied on overcollateralization to enhance the likelihood of payment of the securitized debt outstanding after the final true-up. PECO Energy's choice of credit enhancement, in addition to the periodic true-up mechanism, will depend on a variety of factors, including cost and availability at the time of issuance of the Transition Bonds. PECO Energy intends to use the credit enhancement that will both assure that the Transition Bonds receive the most economical rating and most efficient pricing and at the same time be cost-effective for PECO Energy and its customers. As a result, we cannot now determine the form of credit enhancement; however, for the purpose of determining an effective interest rate as used in Mr. Cohn's testimony, we have assumed the use of overcollateralization at a cost of .75% of the QTE (or approximately $29 million). The type and cost of the credit enhancement to be used will be included in the description of the transaction when PECO Energy provides such information to the Commission after the closing of each issuance of Transition Bonds.

VII. TIMETABLE FOR ISSUANCE OF TRANSITION BONDS

Q. Please describe the proposed timetable for the issuance of the Transition Bonds.

A. Pursuant to the terms of the Competition Act, a utility may request an accelerated determination of its requests for a QRO, in which case the Commission must act within 120 days, but not earlier than fifteen days after the utility has filed its restructuring plan. On that schedule, PECO Energy expects the initial issuance of Transition Bonds to be made on or about June 30, 1997. It is likely that the initial issuance of Transition Bonds will be for an amount less than the full amount requested in PECO Energy's Application for several reasons, including providing a "benchmark" security, as described in Mr. Hiller's testimony. Whether or not the initial Transition Bond issuance is for less than $3.877 billion, we anticipate that all of the Transition Bonds requested in PECO Energy's Application will be issued prior to February, 1998.

Under this timetable, PECO Energy would begin passing on rate savings to customers by mid-1997, upon the successful issuance of the initial amount of

Transition Bonds, with the rate benefits associated with the full $3.6 billion of transition or stranded costs reflected on customer bills after successful issuance of the full $3.877 billion in Transition Bonds, scheduled for February, 1998 or sooner. As described in the section of my testimony concerning use of proceeds, there are sufficient opportunities in that time frame to use the full $3.6 billion to reduce transition or stranded costs and related capitalization.

This timing, however, is also dependent on market conditions existing at the time of the proposed offering, and we have therefore requested in our application that the Commission provide us with a window of two years in which to have the Transition Bonds issued. In addition, market conditions may also affect the terms of the Transition Bonds offered (e.g., maturity), because certain types of bonds may be favored by investors at any one time and pricing could be influenced by the terms of the Transition Bonds offered. The underwriters for the offering will be advising us closely on what to take into consideration concerning the timing of the issuance of the Transition Bonds.

Q. What are the advantages of moving quickly to issue the Transition Bonds?

A. The first and foremost benefit of an early decision by the Commission is that the sooner the Transition Bonds are issued, the sooner our customers will begin to realize savings. PECO Energy and its customers are currently paying an overall cost of capital higher than the anticipated interest rate on the Transition Bonds. The cost savings resulting from this differential are time-sensitive - that is, each day of delay in issuing the Transition Bonds is a day of lost savings of lower capital costs. These lost savings cannot be recaptured in the future.

Second, the savings that can be passed through to customers depend on market interest rates, in particular, U.S. Treasury rates. We believe the current level of savings provided by current market interest rates is attractive. Therefore, PECO Energy does not want to expose customer savings to the risk of higher Treasury rates.

Third, it is expected that PECO Energy will have the largest amount of transition or stranded costs in Pennsylvania. As a result, following the Company's restructuring filing, the Company anticipates requesting authorization for the issuance of a substantial amount of Transition Bonds in excess of those approved in this QRO. Indeed, as discussed by Mr. Hill, PECO Energy has only requested permission in this Application to securitize approximately one-half of its transition or stranded costs. Although the market for Transition Bonds is potentially quite large (as described in Mr. Hiller's testimony), because of the anticipated size of our program, PECO Energy expects that multiple offerings of the Transition Bonds over a period of time will be required. Acting quickly to authorize the issuance of the Transition Bonds requested by this Application will allow the full securitization program to be implemented in an orderly manner in the shortest time possible.

Fourth, investors and the rating agencies view the overall prospects of asset securitization very favorably, resulting in improvements to PECO Energy's general financial health, but PECO Energy will not be able to realize the benefits--or implement its plans for the use of the proceeds--until we receive the Qualified Rate Order and complete the financings. All of these benefits promote the move to competition--and the lower rates to customers that are the object of competition.

All that being said, I wish to emphasize that the future is impossible to predict. At this time, although we intend to do everything possible to meet our proposed timetable which contemplates the initial issuance of Transition Bonds by the end of June, we have requested in our Application that the Commission grant us flexibility in determining the structure and timing of the securitization transaction, including making the ultimate decision of whether or not to go through with the transactions at all. While I believe strongly that it is in the public interest to complete the process of securitization as quickly as possible so that our customers will realize savings in the costs of electricity starting this year, there are many factors beyond our control which may affect the actual issuance of Transition Bonds.

For these reasons, in our Application we request that the Commission grant us a period of two years to complete the process of having the Transition Bonds issued.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit JBM - 1

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The text of this Exhibit will be provided separately subject to a confidentiality agreement.

PECO Energy Debt Outstanding
as of December 31, 1996

Interest Rate	Interest Rate Type	Amount $000	Type	Issue Date	Maturity Date	Call Protected	First Call or Date of Price Change	Call Price	Sinking Fund	Sinking Fund In Effect
7.3800%	Variable (1)	200,000	Commercial Paper	12/31/96	1997-01/02					
5.8000%	Variable (1)	62,500	Term Loan	11/27/96	1997-01/27					
5.8400%	Variable (1)	25,000	Term Loan	12/17/96	1997-02/18					
5.3750%	Fixed	225,000	First Mortgage Bond	8/15/93	1998-08/15	YES	NC			
5.6250%	Fixed	250,000	First Mortgage Bond	11/01/93	2001-11/01	YES	NC			
6.1250%	Fixed	75,000	First Mortgage Bond	10/01/67	1997-10/01		1996-10/01	100.00		
6.3750%	Fixed	75,000	First Mortgage Bond	8/15/93	2005-08/15	YES	1998-08/15	103.05		
6.5000%	Fixed	200,000	First Mortgage Bond	5/01/93	2003-05/01	YES	NC			
6.6250%	Fixed	250,000	First Mortgage Bond	3/01/93	2003-03/01	YES	NC			
7.1250%	Fixed	200,000	First Mortgage Bond	9/01/92	2002-09/01	YES	NC			
7.1250%	Fixed	200,000	First Mortgage Bond	8/15/93	2023-08/15	YES	1998-08/15	104.16		
7.2500%	Fixed	225,000	First Mortgage Bond	11/01/93	2024-11/01	YES	1998-11/01	104.71		
7.3750%	Fixed	80,000	First Mortgage Bond	12/15/71	2001-12/15		1997-12/15	101.20		
7.5000%	Fixed	100,000	First Mortgage Bond	7/15/92	2002-07/15	YES	NC			
7.5000%	Fixed	250,000	First Mortgage Bond	1/15/92	1999-01/15	YES	NC			
7.7500%	Fixed	100,000	First Mortgage Bond	3/01/93	2023-03/01	YES	1998-03/01	104.95		
7.7500%	Fixed	250,000	First Mortgage Bond	5/01/93	2023-05/01	YES	1998-05/01	105.29		
8.0000%	Fixed	200,000	First Mortgage Bond	4/01/92	2002-04/01	YES	NC			
8.2500%	Fixed	250,000	First Mortgage Bond	9/01/92	2022-09/01	YES	1997-09/01	105.20		
8.6250%	Fixed	125,000	First Mortgage Bond	6/01/92	2022-06/01	YES	1997-06/01	105.57		
8.7500%	Fixed	150,000	First Mortgage Bond	4/01/92	2022-04/01	YES	1997-04/01	106.16		
9.2500%	Fixed	75,000	First Mortgage Bond	10/01/89	1999-10/01	YES	NC			
6.9600%	Fixed	10,000	Medium Term Note	7/07/94	1997-04/15	YES	NC			
7.0000%	Fixed	2,000	Medium Term Note	7/11/94	1997-07/11	YES	NC			
7.4100%	Fixed	12,400	Medium Term Note	7/11/94	1998-07/08	YES	NC			
9.0800%	Fixed	30,000	Medium Term Note	12/12/89	1999-12/20	YES	NC			
9.0900%	Fixed	10,000	Medium Term Note	12/20/89	2005-01/14	YES	NC			
9.1000%	Fixed	5,000	Medium Term Note	12/20/89	2005-01/14	YES	NC			
9.1000%	Fixed	5,000	Medium Term Note	12/20/89	2005-01/14	YES	NC			
3.5417%	Variable (2)	50,000	Pollution Control Note	4/01/93	2012-12/01			100.00		
3.5330%	Variable (2)	50,000	Pollution Control Note	4/01/93	2012-12/01			100.00		
3.5312%	Variable (2)	50,000	Pollution Control Note	4/01/93	2012-12/01			100.00		
3.4052%	Variable (2)	4,200	Pollution Control Note	4/01/93	2012-12/01			100.00		
6.6250%	Fixed	29,540	Pollution Control Note	6/01/92	2022-06/01	YES	2002-06/01	102.00		
6.7000%	Fixed	160,560	Pollution Control Note	12/01/91	2021-12/01	YES	2001-12/01	102.00		
7.3750%	Fixed	90,000	Pollution Control Note	4/01/91	2021-04/01	YES	2001-04/01	102.00		
7.6000%	Fixed	27,030	Pollution Control Note	4/01/91	2021-04/01	YES	2001-04/01	102.00		
10.2500%	Fixed	44,688	Private Placement	8/01/87	2007-08/01	YES	2000-08/01	103.24	YES	YES
5.8625%	Variable (1)	87,500	Term Loan	11/06/96	1997-01/06					
5.9250%	Variable (1)	87,500	Term Loan	12/11/96	1997-02/11					
3.4903%	Variable (2)	24,125	Pollution Control Note	8/24/93	2016-08/01			100.00		
4.7281%	Variable (1)	9,075	Pollution Control Note	11/19/96	1997-06/10					
5.1531%	Variable (1)	8,165	Pollution Control Note	9/13/96	1997-06/10					
3.4130%	Variable (2)	23,000	Pollution Control Note	9/09/93	2025-03/01			100.00		
3.5736%	Variable (2)	82,560	Pollution Control Note	2/14/95	2029-06/01					
3.4969%	Variable (2)	13,340	Pollution Control Note	7/02/95	2029-06/01					
3.4903%	Variable (2)	18,440	Pollution Control Note	8/24/93	2016-08/01			100.00		
3.5623%	Variable (2)	34,000	Pollution Control Note	3/27/96	2034-03/01			100.00		
Total		4,535,623								

(1) Interest rate reflects the rate on the last day of the month.
(2) Interest rate reflects the average rate during the month.

PECO Energy Outstanding Capital Stock as of December 31, 1996

Common Stock - no par value

Shares Outstanding	222,542,087
Shares Authorized	500,000,000
Shares Held In Treasury	0

Preferred Stock

Series	Current Redemption Price	Shares Outstanding	$ Amount Outstanding $000
$4.68	$104.00	150,000	$ 15,000
$4.40	112.50	274,720	27,472
$4.30	102.00	150,000	15,000
$3.80	106.00	300,000	30,000
$7.96	- NA -	618,954	61,895
$7.48	- NA -	500,000	50,000
$6.12	- NA -	927,000	92,700
		2,920,674	$292,067

Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership

Series/ Distribution Rate	Current Redemption Price	Shares Outstanding	$ Amount Outstanding $000
Series A / 9.00%	- NA -	8,850,000	$221,250
Series B / 8.72%	- NA -	3,124,183	80,932
		11,974,183	$302,182

Exhibit JBM - 3

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The text of this Exhibit will be provided separately subject to a confidentiality agreement.

PECO STATEMENT NO. 5

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY

FOR ISSUANCE OF A QUALIFIED RATE ORDER

UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY

OF

HOWARD HILLER

Regarding the Receptivity of the Market and Rating Agencies to Transition Bonds

<u>CONTENTS</u>

DIRECT TESTIMONY OF HOWARD HILLER

I. QUALIFICATIONS

Q. Please state your name and business address.

A. Howard Hiller, Seven World Trade Center, New York, NY 10048.

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

A. I am employed by Salomon Brothers Inc ("Salomon" or "Salomon Brothers") as a Vice President in the Fixed Income Capital Markets Group.

Q. Please provide a brief description of Salomon Brothers.

A. Salomon Brothers is a global investment bank that provides international financial services for corporations, governments, supranational organizations, central banks and other financial institutions. Salomon's principal offices are located in New York, London and Tokyo.

Q. Please describe your educational background and prior work experience.

A. I graduated from Cornell University in 1974 with a B.A. in Mathematics. I received an M.S. and Ph.D. in Mathematics from MIT in 1977-78. Between 1978 and 1986, I held a variety of research and teaching positions at Oxford, Yale, Göttingen and

Columbia Universities. In 1986, I joined Citicorp Investment Bank as an Assistant Vice President in the Municipal Finance Group.

Q. Please outline your experience with Salomon.

A. In July 1987, I joined Salomon Brothers and spent four years as a Vice President in the Financial Strategy Group working with utility and industrial clients on fundamental financial policy issues like capital structure, dividend policy and debt management. In 1992, I moved to our Fixed Income Capital Markets Group, focusing on the electric and gas industries. In the period 1993-95, I worked with Puget Sound Power & Light Company ("Puget") on the securitization of regulatory assets corresponding to prior conservation investments that led to the first legislatively supported U.S. utility securitization.

Q. Please describe your responsibilities in your current position at Salomon, particularly as they pertain to utility securitization.

A. I am broadly responsible for providing advice to Salomon Brothers' electric and gas utility clients on the design and execution of capital-raising and liability-management strategies pertaining to debt and preferred stock securities. Currently, a significant portion of my time is committed to the application of asset-backed finance technology to the restructuring of the electric utility industry. Salomon is involved with utility securitization advisory assignments in a number of states, including Pennsylvania, California and Michigan. Prior to the passage of the Electricity Generation Customer Choice and Competition Act ("Competition Act"), Salomon Brothers made presentations to the Pennsylvania Public Utility Commission ("Commission"), state legislators and other interested parties in Harrisburg and to the Pennsylvania Electric Association.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. Please describe the scope and purpose of your testimony.

A. I have been asked by PECO Energy Company ("PECO") to assess the receptivity of the market and the rating agencies to the issuance of Transition Bonds (or "Bonds").

In order to better understand the context in which these Bonds will be evaluated, I will begin by providing, in Section III, an overview of the market for asset-backed securities ("ABS") in terms of historical evolution, asset composition and size. In Section IV, I will describe how Transition Bonds fit into this broader family of ABS classes and how we at Salomon believe that Transition Bonds will be structured and priced, relative to more commodity-like asset-backed securities. I will also indicate which classes of fixed-income investors we expect to buy Transition Bonds and how these securities will be viewed relative to corporate bonds, in general, and electric utility first mortgage bonds, in particular. Finally, in Section V, I will describe by example the customer benefits of a Transition Bond financing.

III. OVERVIEW OF THE ASSET-BACKED MARKET

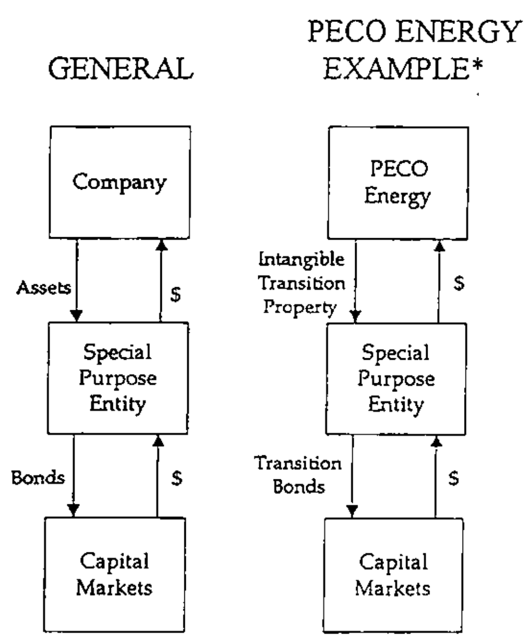
Q. Please briefly describe what is an asset-backed security and how the asset-backed market evolved.

A. The precursor of the ABS market is the mortgage-backed market in which securities are backed by pools of residential mortgages and sold through private mortgage originators or agencies of the U.S. government. The ABS market developed out of the recognition that this technology could be successfully applied to other types of financial and non-financial assets with predictable cash flow streams, including automobile loans, credit card receivables, boat loans, student loans, home equity loans and leases, trade receivables, equipment leases and many other asset classes. The credit quality of these securities depends on the historical and projected analysis of the statistical cash flow characteristics of the underlying assets. Diversification of underlying assets (e.g., many mortgagors, many credit card borrowers) support the credit quality of the securities. The first public market asset-backed transaction was completed in 1985.

Q. What is the basic structure of asset-backed securities?

A. The structure of an asset-backed security depends critically on the underlying assets. In general, the original owner of the underlying assets sells the assets directly or indirectly to a special-purpose entity (an SPE which could be a trust) and that entity issues securities for which the primary source of payment of principal and interest is the cash flow generated by the underlying assets. In the case of Transition Bonds, the assets are Intangible Transition Property ("ITP"). This property is created by the Competition Act by the Commission's issuance of a Qualified Rate Order ("QRO") and represents PECO's right to recover, through Intangible Transition Charges ("ITC"), its Qualified Transition Expenses ("QTE"). The following charts in Figure 1 and Figure 2 represent the overall structure and relationships in a typical securitization and under PECO Energy's preferred securitization structure:

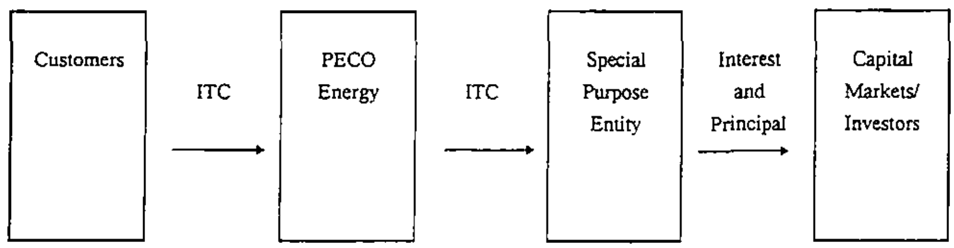
Figure 1: Securitization Structure - Sale and Bond Issuance



* There may be more than one special purpose entity in the final PECO transaction structure.

After issuing the Transition Bonds, the ongoing cash flows of PECO's structure involve: 1) the billing and collection of the ITC from customers by PECO (acting as "servicer" on behalf of the SPE), 2) the transfer of the ITP and the related ITC from PECO to the special purpose entity and 3) the payment of principal and interest to holders of the Transition Bonds.

Figure 2: Ongoing Cash Flow After the Sale of the ITP and the Related ITC and the Bond Issuance



Q. How are asset-backed securities typically rated relative to corporate bonds?

A. The credit analysis of ABS usually focuses on legal structure (e.g., bankruptcy-remoteness), cash flow mechanics, historical quality of receivables (losses, chargeoffs, etc.), servicer mechanics/reliability and credit enhancement. The credit quality of an asset-backed security reflects the ability to analyze the *average* cash flow behavior of large pools of assets, like mortgages. By diversifying exposure across a broad pool of assets, the rating agencies can be comfortable with historical delinquency/loss experience and assess the certainty with which debt service can be covered. In order to then achieve the highest ratings possible, most asset-backed securities take advantage of some form of credit enhancement, such as overcollateralization, reserve funds, third-party bond insurance, guarantees and other structures.

Q. How is this basic structure of asset-backed securities influenced by the asset's cash flow stream?

A. Most assets that are securitized can be divided into two broad categories: *amortizing* and *revolving*. Examples of amortizing assets are installment loans (auto, home equity, student, etc.). Examples of revolving assets are receivables (credit card bills, trade payments, etc.). *Securities backed by amortizing assets* tend to be pass-through in nature, i.e., cash generated by the asset is passed-through to security holders to pay interest due and then retire principal. Note that, if the underlying loans are pre-paid, this cash will be used to accelerate the retirement of principal. *Securities backed by revolving assets* are typically structured to avoid the possibly rapid and irregular repayment of principal that is typical of the underlying assets by deferring principal payment until the end of the transaction. This is accomplished by using the cash generated throughout the transaction to replenish the pool of assets until some specified date prior to maturity, at which point, cash accumulates and is used to retire principal.

Q. Which category of securitized assets cash flow stream applies to the proposed issuance of Transition Bonds described in PECO Energy's Application?

A. The assets in the proposed PECO Energy structure are amortizing assets because, even though the ITC is collected as a stream of revenue from customer payments, a specific QTE balance is being recovered or amortized over time.

Q. How do companies benefit from securitization?

A. For both credit and regulatory purposes, companies that hold financial assets maintain equity capital against them. By securitizing these assets, these companies are able to free up significant amounts of equity capital and, through securitization, access lower-cost sources of debt capital. As a consequence, financial flexibility is enhanced and the company's overall cost of capital is reduced. (See Exhibit HH-1: *Asset Securitization: A Tool for Reducing the Cost of Capital,* Salomon Brothers Inc, Financial Strategy Group, December 1990).

Q. Please describe the size of the asset-backed market in terms of the amount outstanding and its composition by asset categories.

A. The market for asset-backed securities has grown to approximately $347 billion since the first public market offering was completed in 1985. The first public securitization of credit card receivables took place in 1987 and this asset class now dominates the ABS market, constituting over 46% of total outstanding ABS (see Figure 3). Auto loans and home equity loans each contribute about 14%-19% of the market. A third tier of asset classes includes manufactured housing, student loans and equipment leases.

Figure 3. Asset Composition of ABS Market as of 12/1/96 (SEC Registered)

Asset Type	$ Amount (Billions)	% of Total
Credit Cards	$160.3	46.2%
Auto loans	64.1	18.5
Home equity loans	48.1	13.9
Manufactured housing	19.2	5.5
Other	55.0	15.9
Total	**$346.7**	**100.0%**

Source: Bloomberg Services

Q. Please describe the size of the asset-backed market in terms of annual issuance.

A. The pace of annual issuance in the ABS market has risen from $42 billion in 1990 to $148 billion in 1996 (see Figure 4). As the structure of securities and the type of assets eligible for financing in the ABS market continue to evolve and expand, this growth may continue. For example, floating-rate ABS has grown from about 10% of total issuance in 1990 to over 51% in 1996. A number of other innovations include callable structures, Euro and global distribution, zero-coupon structures and non-dollar-denominated offerings. New asset types include New York City taxicab medallions, tax liens and redwood timber rights.

Figure 4. Asset Composition of ABS Issuance for the 12 Month Period ended December 31, 1996 (SEC registered)

Asset Type	**$ Amount (Billions)**	**% of Total**
Credit Cards	$44.4	30.0%
Auto Loans	33.5	22.6
Home Equity Loans	32.6	22.0
Manufactured Housing	7.9	5.4
Other	29.6	20.0
Total	**$148.0**	**100.0%**

Source: Salomon Brothers Asset-Backed Research

Q. What is the typical dollar amount of a securitization financing?

A. The average size of ABS offerings has increased significantly over the last several years. It is now common for the larger credit-card issuers -- Citibank, Chase, MBNA and Discover -- to place $1-$2 billion of securities in a multi-tranche offering in a single day (see Figure 5). Many issuers will also revisit the capital markets frequently in the course of a single year. As an example, we have listed several offerings -- from different asset classes -- that were at least $1 billion in size in 1996:

Figure 5. Selected Asset-Backed Offerings in 1996 ($ in Billions)

Offer Date	Issuer	Asset Class	$Amount (Billions)
9/10	Chase Manhattan Grantor Trust 1996-B	Credit Cards	$ 1.4
8/7	MBNA Master Trust II 1996-H	Credit Cards	1.0
6/13	Ford Credit Auto Owner Trust 1996-A	Auto Loans	1.0
4/23	Discover Card Master Trust 1996-4	Credit Cards	1.0
4/23	Beneficial Home Equity Loan Trust 1996- 1	Home Equity	1.1
2/15	Chase Manhattan Grantor Trust 1996-A	Credit Cards	1.5
1/11	Citibank Credit Card Master Trust 1996-1	Credit Cards	1.0

Source: Securities Data Company

Q. How does the size of the ABS market compare to that for investment-grade corporate bonds and electric utility bonds?

A. The annual issuance volume of asset-backed securities now rivals that of the corporate bond market. For example, in 1996, asset-backed issuance approached that of investment-grade corporate bonds ($148 billion vs. $185 billion), while in 1993, ABS issuance was only 31% of total corporate bond issuance. Electric utilities issued only $5-$6 billion of corporate debt in each of 1995 and 1996.

Q. How do investors compare asset-backed securities to corporate bonds from the perspectives of structure and credit?

A. Asset-backed securities are fundamentally different in structure and credit profile from traditional corporate bonds. Most corporate bonds are "bullet" maturities, meaning all the principal is paid in a single payment on a date-certain maturity. In contrast, asset-backed securities are often subject to uncertainty with respect to the timing of principal repayment. For example, if the underlying auto loans of an auto loan-backed security are prepaid at a faster rate than expected, the repayment of principal to investors will be accelerated. Conversely, If many of the underlying loans are delinquent, investors may receive their principal dollars later than originally expected. The credit analysis of ABS is also fundamentally different, focusing on the assets themselves and on structural considerations, including those which isolate the assets from the credit risk of the corporate enterprise, rather than the operating performance of the overall corporate enterprise. Nonetheless, the credit quality of both securities will reflect larger macroeconomic factors and their possible impact on the underlying assets' cash flow generation capabilities.

Q. How are asset-backed securities valued and how does this compare to corporate bonds?

A. Similar to most fixed-income securities, ABS are priced relative to a comparable term of U.S. Treasury securities. Because asset-backed securities usually are not strictly "bullet" securities, they will tend to trade relative to an expected average life, i.e., the expected average principal repayment date. For example, a "generic" AAA-rated 2-year auto loan ABS is valued by investors at about 40 basis points (bp) over the benchmark 2-year U.S. Treasury yield (currently 6.04% + .40% = 6.44%). In spite of their pristine credit ratings, ABS do not typically trade at spreads over U.S.

Treasury securities as narrow as AAA-rated corporate bonds. For example, a hypothetical 2-year AAA-rated bond issued by an industrial company would probably trade at about 20 basis points over the benchmark U. S. Treasury yield. The spread premium required for auto loan ABS primarily reflects the uncertainty of the exact timing of investors' return of principal, unlike the one-time payment or "bullet" structure that corporate bonds offer.

Q. Who are the typical buyers of asset-backed securities?

A. Asset-backed securities are purchased by many classes of institutional fixed-income investors including insurance companies, investment advisors, U.S. and international banks, securities lenders and corporate cash managers. The latter two classes of investors purchase primarily floating-rate ABS. We expect that Transition Bonds will be attractive to each of these ABS investor groups as well as traditional utility first mortgage bond buyers.

IV. TRANSITION BONDS: A NEW CLASS IN THE ABS MARKET

Q. How will the Transition Bonds differ from other asset-backed securities?

A. There are a number of important differences. First, in a typical receivables securitization transaction, the receivables have already been generated. For instance, when Citibank securitizes its credit card receivables, it is selling to the SPE the right to collect payments already owed by Citibank's credit card holders. In the PECO Energy transaction, the asset being securitized is not a pool of current receivables (i.e., PECO Energy's customers have not yet been billed ITC, so there are no receivables on the books of PECO Energy). The SPE will purchase the right to collect amounts from PECO Energy's customers which will be billed over the course of the transaction. This is an important distinction for several reasons. The credit analysis will address not only the charge-off experience as in a normal receivables securitization, but also the ability of PECO Energy to generate the receivables by providing service to customers. In order to mitigate this risk, legislation is required which creates the irrevocable right (the ITP) to ITC collections sufficient to fully recover QTE, whether billed by PECO Energy or a successor entity. It is this statutory right to future revenues which is the basis for the securitization rather than the existing receivables. Additionally, because the asset being securitized represents the right to a future revenue, the legislation is also required to provide for a bankruptcy-remote sale of the ITP (in a securitization of existing receivables, this can be achieved structurally without state legislation).

Second, a unique type of credit enhancement - the true-up mechanism - will be employed to ensure a high certainty of debt service payment. The credit analysis of the Transition Bonds will be affected favorably by the true-up mechanism for adjusting the ITC. Although the true-up mechanism does not completely eliminate the need for other forms of credit enhancement, it should significantly minimize the amount and cost of this credit enhancement. Another form of credit enhancement available is overcollateralization. Overcollateralization exists when security holders have purchased or are secured by an asset and its related revenue stream whose value is sufficiently in excess of the investment made by security holders to assure the likelihood of repayment (commensurate with the rating of the securities) of the investment and a return thereon. With the addition of a "true-up" mechanism, the application of overcollateralization is limited to the unamortized amount of securities to be paid following the final "true-up" (i.e., any collection shortfalls throughout the transaction will be recovered via the "true-up" mechanism until the last "true-up," after which the ITC will no longer be subject to adjustments). As a result, any shortfalls thereafter will be "absorbed" by the overcollateralization. Because the ITC will be calculated in order to recover an asset which is greater than the Transition Bond balance outstanding, collections could be lower than expected and still be able to fully amortize the Transition Bonds. The result is a smaller dollar amount or value of overcollateralization required than would be the case without the "true-up" mechanism. For example, in the Puget securitization transaction, which included a "true-up" provision, the required overcollateralization was 0.12% ($244,850) of the initial principal balance ($202,250,000), significantly less than the traditional 10%-15% ($20 million - $30 million) that would have been required in securitization transactions that used only overcollateralization.

Q. Please provide an overview of the Puget transaction.

A: The Washington legislature and the Washington Utilities and Transportation Commission ("WUTC") allowed Puget to isolate the revenue stream that was designated to recover conservation expenditures in order to make that revenue stream more creditworthy. This was done by, among other things, establishing in the legislation that the revenue stream associated with the conservation expenditures was property that could be bought and sold and made the basis for the issuance of securities. Neither the Washington legislature nor the WUTC could reopen or revisit the issue of whether Puget was entitled to collect that revenue stream from its customers. When Puget subsequently sold this property to a financing entity, the revenue stream became even more creditworthy because it was completely separated from any of Puget's credit risks (i.e., a Puget bankruptcy should not be expected to impact the collectibility of this revenue stream). Indeed, other than acting as the servicer or collection agent for the revenue stream, Puget had no legal or financial interest in the segregated asset. Because there was a creditworthy revenue stream that provided a future mechanism to pay any debt, the purchaser of the revenue stream (i.e., the financing entity) was able to issue lower-debt in order to raise the money that it needed to purchase the revenue stream from Puget and eliminate the return on equity previously included in Puget's base rates.

Q. How do Transition Bonds structurally compare to other asset classes?

A. Salomon expects that Transition Bonds will be a new and attractive asset class for fixed-income investors. Like issuances backed by auto loans and other amortizing assets, Transition Bonds are essentially "pass-through" securities. But unlike issuances backed by auto loans, with average lives of 2-3 years, Transition Bonds, with maturities of up to 10 years, should offer longer average lives and only minimal amortization uncertainty due to the true-up mechanism.

Q. How will Transition Bonds be priced relative to other asset-backed securities and electric utility first mortgage bonds?

A. Credit card securities serve as an established reference point for the entire ABS market. We believe that investors' natural tendencies will be to compare a Transition Bond to a credit card security with an expected final maturity equal to the Transition Bond's average life. Investors will need to assess the amortization risk versus a credit-card security and the legislative/regulatory risks inherent in Transition Bonds to determine an appropriate spread premium. The overall competitive financial profile of the utility may also influence investors' assessment of Transition Bond pricing. Taking all of these factors into account and given the current level of interest rates, I believe that the rated Transition Bonds contemplated in PECO Energy's preferred structure could be issued at a coupon rate of approximately 7-7 1/4% relative to a current 10-year Treasury yield of about 6 1/2%. If PECO Energy were issuing

10-year first mortgage bonds today, they would bear a coupon rate of approximately 7.6%.

Q. How will the nature of the ITC affect the issuance of the Transition Bonds?

A. The choice of customer versus usage-based charges will likely reflect the utility's established use of fixed charges in its core rate design. We believe that in both cases the transaction can be structured so that the securities are capable of achieving AAA ratings. Although either method can be used, their cost impacts may vary according to the difference in the credit enhancement (i.e., the frequency of true-ups and amount of overcollateralization) required for each method. Therefore, the sooner the Transition Bonds are issued, the sooner investors will be able to evaluate an actual security in the market.

Q. What are the advantages and disadvantages of PECO Energy being the first utility to securitize Intangible Transition Property?

A. Securitization creates rate reductions for customers and, therefore, achieving those savings sooner rather than later is clearly beneficial because each day of delay in issuance of Transition Bonds is a day of savings lost for customers. In addition, PECO Energy has been viewed in the market as a leader in securitization efforts in Pennsylvania and the market expects to see PECO Energy take advantage of the expedited rate filing procedure as quickly as possible. The market will respond positively to PECO Energy's proactive approach to implementing what is viewed as an important tool for preparing PECO Energy for a competitive future. In addition, rates are attractive now and PECO Energy should be in a position to take advantage of them.

Although it is likely that the market could absorb a large amount of Transition Bonds in a single transaction, we expect that for a new product it will probably be advantageous to establish a benchmark security. Investors can then readily observe the trading characteristics of this security in the secondary market to more easily evaluate the pricing of subsequent offerings. Therefore, the sooner the Transition Bonds are issued, the sooner this benchmark will be established.

In addition, if PECO Energy wants to maximize the efficiency of retiring outstanding debt and equity, it may be preferable to accomplish this over time, rather than at a single point in time. Mr. Mitchell discusses in his testimony the portion of Transition Bond proceeds that will be applied to the reduction of debt and equity securities.

While it is impossible to predict now, with many states passing competition legislation, there is some minimal risk of market saturation by Transition Bond-type securities in the future.

Q. What does Salomon Brothers believe is the likely market response to the Transition Bond offering?

A. We believe that the inaugural offering will likely receive an enthusiastic reception from investors. We are confident that, given the necessary regulatory approvals the resolution of the structural issues and the absence of a significant deterioration of the conditions in the bond market, we will be able to market the full $3.877 billion of Transition Bonds at favorable rates within several months of PECO Energy receiving a QRO. The fixed-income community has been and will continue to be inundated with information on this topic well in advance. The rating agencies will submit the structure of the securities to detailed stress test analyses and carefully review the legal structure of the transaction, any perceived regulatory risk and the systems that the utility has put in place to keep track of ITC collections.

V. BENEFITS OF TRANSITION BONDS: HOME MORGAGE EXAMPLE

Q. For comparative purposes, please provide a simple example of the structuring and economic benefits of a home mortgage loan?

A. The refinancing of a home mortgage captures all the critical economic aspects of the Transition Bond financing. Assume that the homeowner has a mortgage balance of $100,000 with 15 years remaining on an original 30-year mortgage *with an interest rate of 12%. (For ease of calculation, we will assume that the* mortgage interest is paid annually, rather than the more typical monthly frequency. For those interested, the assumed original mortgage was $118,269.63). The annual payment on this mortgage is $14,682.42. Assume that the current mortgage is prepayable without penalty and a new 15-year mortgage is available to the homeowner at 9%. For simplicity, we assume this new mortgage is offered without up-front points and we will ignore all transaction expenses. The annual payment on this new mortgage is $12,405.89, a savings of $2,276.53, or a 15.5% reduction in annual mortgage carrying costs. In the case of a Transition Bond financing, the old mortgage corresponds to PECO Energy's current recovery of and return on (including an equity return) certain stranded assets and the interest rate on the new mortgage is the effective cost of the Transition Bond issuance. Note that in the example, we are refinancing the entire asset - the house - and hence the savings are relative to the total payment. In the case of Transition Bonds, we are only refinancing a portion of PECO Energy's assets - its stranded assets - and therefore the percentage savings will be smaller depending on what portion of PECO Energy's assets are deemed appropriate for the securitization process.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit HH-1

Salomon Brothers

Financial Strategy Group/Structured Finance Group

Asset Securitization: A Tool for Reducing the Cost of Capital

by
Peter B. Blanton
Hanif S. Mamdani

December 1990

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Table of Contents	Page
Introduction	1
Definition	1
Traditional Funding	2
The Asset Securitization Advantage	3
The Cost of Capital Implications	3
• Debt Financing Savings	4
• Equity Financing Savings	5
• Credit Enhancement Costs	6
The Cost of Capital Savings of Asset Securitization versus Balance Sheet Funding: An Example	6
Conclusion	8
Appendix. The Weighted-Average Cost of Capital Savings from Funding Through Asset Securitization	9
Figure 1. Asset-Backed Securities Issuance in the United States, 1986-90	2
Figure 2. Total Cost of Capital Savings of Asset Securitization	4
Figure 3. Equity Requirements Before and After Asset Securitization	6
Figure 4. Cost of Capital Savings	8

Asset Securitization: A Tool for Reducing the Cost of Capital

by
Peter B. Blanton
Hanif S. Mamdani

Introduction

Because of the increased volatility in the financial markets and rating agency and regulatory concerns about deteriorating credit quality, traditional funding methods may not always provide the best financing and capital structure solutions. Instead, an increasing number of industrial and financial companies have turned to **asset securitization**. Companies that hold financial or marketable assets may be able to use asset securitization to free up equity capital, decrease after-tax borrowing costs, reduce balance sheet leverage, diversify funding sources, and improve the interest rate matching of assets and liabilities.

For many issuers, the most important advantage of securitization is that it can release substantial amounts of equity capital. For example, companies that originate loans or other receivables generally are required by the rating agencies or creditors to maintain a costly layer of equity to hold these loans or receivables to maturity. In other words, companies that rely on their balance sheet to fund their receivables consume valuable equity capital. However, by securitizing these assets, a company may need to reserve significantly less, if any, equity capital.[1] Thus, asset securitization can lead to a substantial reduction in a company's overall cost of capital, as freed-up equity is redeployed to originate more business or is returned to the shareholders.[2]

Definition

The essence of asset securitization is the sale of marketable securities backed by the cash flows or market value of specified assets.[3] This market developed from the securitization of residential mortgages, in which mortgage originators and the U.S. housing finance agencies sell securities backed by pools of individual residential mortgages. In recent years, the financing and structuring concepts developed in the mortgage-backed securities market have been applied to other types of financial receivables, including commercial mortgages, automobile loans, credit card receivables, boat loans, trade receivables, and equipment leases. Issuers of asset-backed securities include commercial banks, captive finance companies, savings

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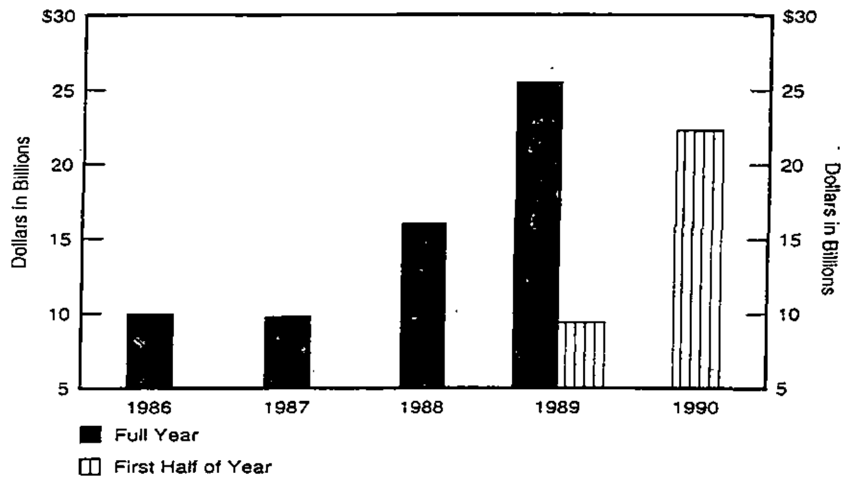
[1] For example, the primary objective for many commercial banks in issuing credit card-backed securities is to free up regulatory capital. Under the new risk-adjusted capital guidelines, banks must increase their capital-to-asset ratio to 8% by 1992, which can be accomplished by selling assets in securitized transactions.

[2] For any given portfolio of amortizing assets (such as mortgages, leases and revolving credit balances), the amount of equity required by traditional funding declines as the principal of the receivables pays down to zero by maturity. Therefore, the amount of equity that is potentially released by asset securitization for a specific pool of assets declines over time. To achieve a permanent reduction in equity, a firm would need to use asset securitization as an ongoing financing tool. In practice, the net effect of amortizing asset pools and periodic (that is, lumpy) asset securitization issues would be to cause the amount of released equity to follow a saw-tooth, or jagged, pattern.

[3] In general, assets that can be securitized have good credit histories and stable and predictable cash flows. For more information on the structure of asset-backed securities, see *A Review of Asset-Backed Securities*, K. Jeanne Person, Salomon Brothers Inc, September 1987.

institutions, manufacturers, and retailers. As shown in Figure 1, the market for asset-backed securities has grown substantially since 1986.

Figure 1. Asset-Backed Securities Issuance in the United States, 1986-90[a]
(Dollars in Billions)



[a] Source: Salomon Brothers Inc. Excludes all mortgage-backed securities.

Traditional Funding

Traditionally, companies finance the receivables that they originate by issuing corporate debt securities similar in maturity to their receivables (known as "match funding," or "balance sheet financing"). To preserve current debt ratings and market access, **financial companies** are required by creditors and rating agencies to establish a layer of equity as protection from the various risks associated with holding the receivables to maturity. This layer can be a significant fraction of the total assets, typically in the 7%-10% range.

An **industrial company**, in financing its receivables, also must reserve a portion of its equity to protect against risks. Although creditors and rating agencies may not require an industrial company to explicitly set aside a layer of equity each time that the company raises debt to finance new receivables, the company is implicitly drawing upon its existing equity base to fund these assets. Assuming that these receivables are similar to those of the average finance company, 7%-10% equity-to-asset ratios may be appropriate.[4]

In extending credit to their customers, financial and industrial firms often wear several hats: originating and servicing receivables or loans; evaluating credit risks; managing a changing portfolio of assets; and funding assets to minimize the adverse effects of interest rate movements. Given the number of risks that the firm must absorb, it is not surprising that its creditors and rating agencies require a substantial layer of equity support.

[4] In theory, the amount of equity should be based on the quality and riskiness of the receivables and not necessarily on the amount of equity required to support the company's operating activities. Often, however, high-quality financial assets are not sufficiently differentiated by the market in evaluating the firm's leverage and credit standing. In these situations, the industrial company may have to provide more equity than that required for a typical finance company.

The Asset Securitization Advantage

Unlike traditional funding methods, where the company absorbs all of the risks of originating receivables with a generous layer of equity, asset securitization externalizes these risks. By partitioning risks and parcelling them out to better-suited participants in the capital markets (including money managers, pension funds, insurance companies, and overseas investors), these risks can be managed more efficiently. The result is a substantial reduction in the equity capital required to fund the securitizable assets.

• **Credit Risks.** In a securitized financing, the issuer isolates the default risk of a specific pool of receivables or loans in a special-purpose vehicle. The establishment of this special-purpose vehicle defines clearly the assets and their risks, facilitating the purchase of catastrophic (high default rate) insurance through a letter of credit or another form of credit enhancement, such as a senior/subordinated structure.[5] In general, the financial institution or the institutional investor that provides such credit support often is better able to absorb this risk through the diversification of a wide base of investments.[6]

A company that has receivables concentrated in certain industries or regions faces additional credit risk. Given this lack of diversification of receivables, these companies may be required by their creditors and rating agencies to provide wider equity buffers. Asset securitization, however, allows other investors to diversify these pools of receivables. Buyers of asset-backed securities may be able to build diversified portfolios that are insulated from specific industry, regional or demographic risks.

• **Asset/Liability Management.** Asset securitization also transfers interest rate — and in some cases, prepayment — risks to investors in asset-backed notes. When using the balance sheet to fund a portfolio of receivables, firms are exposed to the risk that assets and liabilities will not be matched perfectly in terms of sensitivities to changes in interest rates or principal repayments. However, by shifting these risks to the professional risk managers that typically invest in asset-backed notes, originators of receivables or other financial assets can manage these asset/liability management risks at a lower cost than by using up valuable equity capital.

Furthermore, by clearly defining the pool of assets to be funded, asset securitization eliminates the need to protect investors from a potential deterioration in the issuer's overall credit quality. Because creditors may have little control over a possible change in a company's business or financial risks, banks and buyers of corporate credit may require additional equity capital as a safeguard. Unlike corporate debt issues, asset-backed securities are designed to be insulated from credit risk shocks, such as corporate releveragings or hostile takeovers.

The Cost of Capital Implications

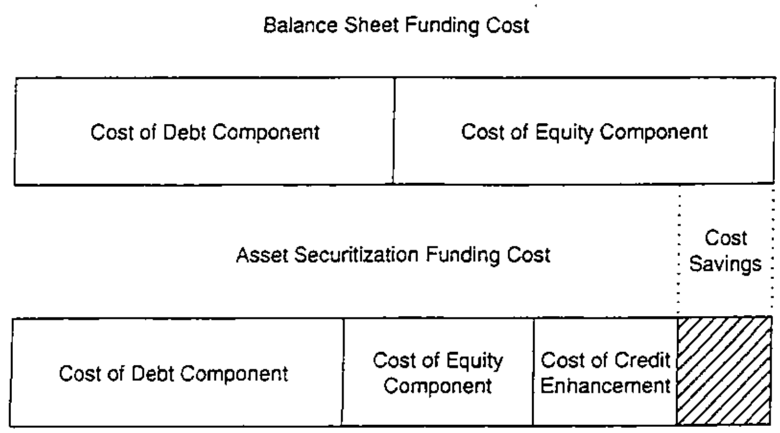
The advantages of unbundling and partitioning the funding process can result in a direct reduction in a company's cost of capital. These reductions stem from attractive after-tax borrowing costs and a more efficient

[5] In a typical senior/subordinated structure, two classes of securities are issued: (1) a senior class that often has a triple A rating and first claim on the cash flows and assets of the pool; and (2) a junior class that has a lower credit rating and a subordinated interest to the senior tranche.

[6] In some situations, issuers may provide some credit enhancement themselves by retaining a portion of the subordinated piece.

allocation of equity capital. Because the amount of equity capital required in an asset securitization can be less than with traditional balance sheet funding, it is important to compare the **total cost of capital**, not merely the debt financing differences of the two funding alternatives. As shown in Figure 2, the cost of capital savings is a function of the differences in debt and equity costs, as well as the additional credit enhancement costs of securitization.

Figure 2. Total Cost of Capital Savings of Asset Securitization



Note: Not drawn to scale.

Debt Financing Savings

Asset securitization may provide several distinct advantages over alternative forms of debt financing, such as commercial paper, medium-term notes or underwritten debt instruments. These advantages may include an additional market for the issuer's debt securities, lower borrowing costs, freedom from restrictive bond covenants, and substantial tax savings for the multinational corporation.

- **Alternative funding source.** Asset securitization provides an important funding alternative to the corporate debt markets and typically accesses a different base of institutional investors. The addition of a new funding source through asset securitization should add to a firm's financial flexibility, while leaving access to the usual funding sources unimpaired.

- **Lower borrowing costs.** Financial and industrial companies with less than top credit ratings may be able to utilize the higher quality credit of their receivables to access funds at otherwise unobtainable double A or triple A ratings.

- **No debt covenants.** In an asset securitization, the assets and associated cash flows are segregated from the corporate activity of the issuer, and therefore, investors should be shielded from the effects of leveraged recapitalizations or hostile takeovers. Thus, issuers can use asset securitization to avoid the restrictive event risk or other covenants contained in many new corporate debt issuances.[7]

[7] To alleviate investor concerns that certain leveraged transactions may dilute the value of their bonds, some corporate debt issues contain indenture covenants that require the issuer to redeem or enhance the value of the bonds upon certain releveraging events.

• **Tax savings.** Companies that have substantial overseas operations may find that asset securitization provides a lower **after-tax** cost of financing than traditional debt financing (even if the pretax cost is higher) by avoiding the unfavorable foreign tax credit interest allocation rules.

In general, multinational corporations must allocate a portion of their U.S. interest expense against foreign source income when determining the credit allowed against their U.S. tax liability for foreign taxes paid. Because the foreign tax credit calculation is based on the proportion of foreign source income to total income, the requirement that U.S. interest expense be allocated against foreign source income reduces the allowable foreign tax credit. To the extent that interest allocation creates a "shortfall" of foreign tax credits (that is, foreign taxes paid exceed the allowable U.S. tax credit), a U.S. multinational will lose any tax benefit for a portion of its U.S. interest expense.

An asset securitization that is structured as a sale of assets for tax purposes, however, allows a company to raise cash proceeds without incurring additional, allocable interest expense. Whether used to fund operations or to pay down existing interest-bearing debt, an asset securitization transaction can reduce a company's overall U.S. interest expense and improve its after-tax borrowing costs.[8]

Equity Financing Savings

As discussed earlier, asset securitization generally requires a smaller equity buffer than traditional balance sheet funding by reducing the issuer's exposure to interest rate, prepayment and default risks.[9] With lower equity requirements, asset securitization can lead to a significant reduction in a company's total equity costs. Specifically, in an asset securitization, the issuer limits or eliminates its potential exposure to high levels of defaults or prepayments and interest rate mismatch risk. In those cases where the issuer has no residual risks (no contractual obligations to support the transaction under any contingency), we believe that virtually no equity is required.[10]

In other asset securitization transactions, an issuer may need to contribute a (nonrefundable) good faith deposit. For example, in a credit card asset securitization, the issuer may advance 2% of the transaction to a reserve account to cover any temporary earnings shortfalls. Although typically nominal in size, these deposits can be viewed as the equity capital supporting the transaction. Other structures may require a degree of self-insurance in which the issuer reimburses any losses in the asset portfolio up to some predetermined level. In these cases, the market by and large does not impose any additional equity cost upon issuers of asset-backed securities for recourse in excess of the expected losses on the asset pool.[11] Even if originators were required to fully support the recourse level, such a requirement still would tie down less equity than the amount of equity consumed in balance sheet financing.[12]

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[8] See *Corporate Financing Strategies Arising From the New Expense Allocation Rules Pursuant to the Tax Reform Act of 1986*, Salomon Brothers Inc, March 1987.

[9] Although an asset securitization can eliminate a company's economic exposure to a fixed pool of assets, selling assets that are higher in quality than the rest of the portfolio may increase the amount of equity required for these remaining assets. In other words, by reducing the quality of the remaining assets, the issuer may need to reserve a higher equity level per dollar of assets than before. Although not common, this drain on equity would tend to occur if the issuer were to "cherry pick" its high-quality assets for the asset securitization.

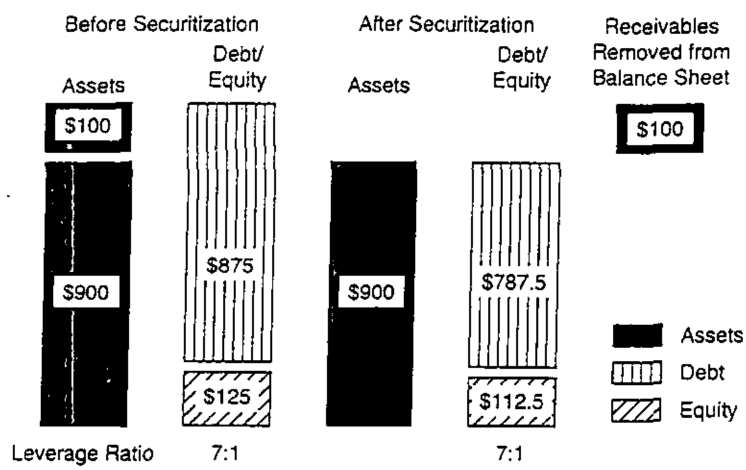
[10] Issuers who rely heavily on asset securitization may have an implicit agreement to support their asset securitization transactions beyond their legal obligation.

[11] The expected losses on most pools usually are less than the equity required in a typical balance sheet funding. Thus, in these situations, we can argue that asset securitization frees up some equity.

[12] See "Analyzing the Economic Benefits of Securitized Credit," *Journal of Applied Corporate Finance*, James Rosenthal and Juan Ocampo, Fall 1988.

The reduced equity requirements of asset securitization are examined in the following simple example. A company with assets of $1,000 million has a debt-to-equity ratio of seven to one and equity of $125 million. If this company were to securitize $100 million of its receivables, less equity would be required. Assuming that the securitized receivables require no equity backing by the issuer, the firm can maintain the same debt ratio of seven to one with only $112.5 million in equity. As shown in Figure 3, the securitization of the receivables has liberated $12.5 million in equity for the firm.

Figure 3. Equity Requirements Before and After Asset Securitization
(Dollars in Millions)



Credit Enhancement Costs

The costs of credit enhancement offset some of the savings from lower debt and equity costs. These costs may be in the form of a third-party guaranty, such as a surety bond issued by an insurance company or a bank letter of credit, or through a subordination of the seller's retained interest. The form and magnitude of credit enhancement depend on the issuer and the underlying assets. The choice between self-insurance or a third-party guaranty typically depends on an analysis of the cost of the guaranty and the improvement in pricing resulting from the enhanced credit of the issue. Existing debt covenants that prohibit recourse transactions also can be a factor in deciding whether to seek third-party credit enhancement.

The Cost of Capital Savings of Asset Securitization versus Balance Sheet Funding: An Example

The next example illustrates how to measure the total cost of capital savings from asset securitization. In addition, the Appendix provides a simple derivation of a formula for estimating these cost savings.

Situation

A multinational manufacturing company needs to raise $200 million to finance the modernization of one of its production facilities. The company traditionally has financed its growth with a combination of retained earnings and publicly issued debt to maintain a target leverage ratio. However, the large amount of trade receivables currently on the company's balance sheet has prompted management to consider asset securitization as an alternative to traditional financing.

Debt Financing Savings

The company's pretax borrowing cost on publicly issued intermediate corporate debt (single A rated) is 9.60%, representing a 100-basis-point spread over the five-year Treasury rate of 8.60%. However, the pretax cost on the triple A-rated asset securitization debt is 9.35% — 75 basis points over Treasuries. On an after-tax basis, the cost of debt for a traditional borrowing and for a securitized borrowing is 6.33% and 6.17%, respectively, assuming a marginal tax rate of 34%.[13] Thus, the debt financing cost savings from asset securitization is approximately 16 basis points, or[14]

Savings in Debt Financing Cost = (1 - 0.34) x (9.60% - 9.35%) = 16bp

Equity Financing Savings

Traditionally, when financing assets such as receivables, the company implicitly reserves an amount of equity roughly equal to 7% of the assets. However, with the proposed asset securitization transaction, the company is required to provide an initial equity injection of only 2% of the assets. Thus, the amount of equity released through the securitization of the receivables is equal to approximately 5% of the assets. The implied savings from being able to replace some of the relatively expensive equity capital with tax-deductible debt is equal to the amount of equity replaced with debt multiplied by the cost-of-capital premium of equity over debt. Management has estimated the cost of equity at 16.00%, [15] resulting in a cost of capital premium of about 9.83% over the after-tax cost of securitized debt (6.17%). With 5% of the equity being released and replaced with debt, securitization results in an equity financing cost savings of about 49 basis points.

Savings in Equity Financing Cost = (7% - 2%) x (16.00% - 6.17%) = 49bp

Credit Enhancement Costs

This hypothetical asset securitization structure utilizes external credit enhancement in the form of a bank letter of credit. In this case, an international bank has agreed to provide a letter of credit that protects investors from losses of up to 10% of the total asset value for an annual fee of approximately six basis points.

Total Cost of Capital Savings

The total cost of capital savings, as estimated by the company, is a savings of 16 basis points on the debt, plus a savings of 48 basis points from the freeing of equity capital, less a six-basis-point fee for the required credit enhancement (or four basis points after taxes), yielding a net after-tax savings of approximately 61 basis points (see Figure 4).

Total Cost of Capital Savings = 16bp + 49bp - 4bp = 61bp

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[13] Because of foreign interest allocation rules, the after-tax savings from asset securitization may be even higher. For example, if the company currently loses the benefit of a deduction for tax purposes of 10% of its interest expense because of interest allocation problems, a securitized financing could save the company an additional 33 basis points in debt financing costs versus traditional financing. If only 90% of the interest on traditional debt is deductible, the tax shield on interest expense is 2.94% (90% x 9.60% x 34%). Thus, the after-tax cost of that debt is 6.66% (9.60%-2.94%) versus the after-tax cost of 6.33% (9.60% x (1-0.34)) for fully deductible interest expense. The difference between 6.66% and 6.33% is 33 basis points.

[14] This simple formula provides a close approximation of the true savings. Because the receivables are not 100% debt financed, the actual savings may be slightly less. For example, if we assume that the receivables are 93% debt financed (similar to a finance company), the debt financing savings are 15 basis points. See the Appendix for the exact formula.

[15] Theoretically, the appropriate cost of equity should be based on the riskiness of the assets being funded. For finance companies, the firm's overall cost of equity usually is a suitable proxy for the cost of the equity used to finance additional assets. However, for nonfinancial companies, it may be difficult to estimate the cost of equity for this financing activity separate from the firm's overall cost of equity. One method of approximating this hypothetical cost of equity is to use the cost of equity for a typical finance company as a proxy, which in this case, is assumed to be 16.0%. (See the Appendix for more information on calculating the cost of equity).

This after-tax savings of 61 basis points on a $200-million securitization represents an annual reduction in financing costs of $1.22 million. **As a result of asset securitization, the company has shrunk the balance sheet, and reduced leverage and the cost of capital, but retained the earnings stream on its core assets.**

Figure 4. Cost of Capital Savings

Assumptions	
Corporate Debt Rate	9.60%
Asset-Backed Security Rate	9.35
Cost of Equity	16.00
Credit Enhancement Cost	0.06
Marginal Tax Rate	34.00

	On-Balance-Sheet Funding		Asset-Backed Funding	
	Costs	Capital Mix	Costs	Capital Mix
After-Tax Cost of Capital				
Cost of Debt	6.33%	93.00%	6.17%	98.00%
Cost of Equity	16.00	7.00	16.00	2.00
Cost of Credit Enhancement	—	—	0:04	—
Weighted-Average Cost of Capital	7.01%		6.40%	
After-Tax Cost of Capital Advantage	0.61%			

Conclusion

An increasing number of industrial and financial companies have accessed the asset securitization market because of the compelling cost of capital advantages. For these companies, equity capital may be in short supply or too expensive to use in funding otherwise securitizable assets. Through asset securitization, the risks and costs of owning a financial asset are separated from the uses of that asset. Industrial corporations can maintain or increase the level of business activity, without tying up equity in financing the receivables generated by their basic operations. Financial institutions can derive servicing fees and other benefits from the origination of loans while removing these assets from their balance sheets. By freeing up substantial amounts of equity capital and tapping alternative debt markets, asset securitization represents a distinct and cost-efficient funding methodology.

* * *

Appendix. The Weighted-Average Cost of Capital Savings from Funding Through Asset Securitization

In this section, we formulate how the total (debt and equity) cost of funding assets can be less with asset securitization than with more traditional balance sheet funding methods. Specifically, the reduction in the total financing costs can be expressed as the savings in the firm's weighted-average cost of capital (WACC) from asset securitization over balance sheet funding.

WACC Savings = WACC (Balance Sheet Funding) - WACC (Asset Securitization)

- **Cost of Capital from Balance Sheet Funding.** The weighted-average cost of capital of traditional balance sheet funding can be expressed simply as the weighted-average after-tax cost of the debt and equity used to finance the assets.

WACC of Balance Sheet Funding	=	Proportion of Debt	x	After-Tax Cost of Debt	+	Proportion of Equity	x	Cost of Equity, or
WACC(BS)	=	$(1\text{-}Eq\%_{bs})$	x	$(1\text{-}T)\ k_d$	+	$Eq\%_{bs}$	x	k_e

- **Cost of Equity.** For many financial and industrial companies, the cost of equity can range from 13% to 18%, which is the return on equity investment (dividends *plus* capital appreciation) required by the shareholders. To estimate the cost of equity for a specific company or financial subsidiary, we can utilize the capital asset pricing model (CAPM). This model states that the cost of equity equals the risk-free rate (approximated by the current long Treasury bond yield); *plus* beta (a measure of the riskiness of the stock), *times* the equity market risk premium (the excess return that investors require for bearing the risk of the equity market over a risk-free investment in long-term U.S. Treasury Bonds). Assuming a beta of one,[16] which implies that the equity risks attributed to the financial assets are similar to the risks of the overall market, a risk-free rate of 8.6% and an equity risk premium of 7.4% (the average excess of common stock returns over intermediate-term Treasury Bond yields from 1926 to 1989 as measured by Ibbotson Associates),[17] the cost of equity is 16.0%.[18]

Cost of Equity	=	Risk-Free Rate	+	(Beta X Equity Market Risk Premium), or
16.0%	=	8.6%	+	(1.0 X 7.4%)

- **Cost of Capital of Asset Securitization.** The total cost of asset securitization is the weighted average of the cost of the debt and equity required to support the structure, *plus* the cost of any required credit enhancements (for example, letter of credit fees).

WACC from Securitized Financing	=	Proportion of Debt	x	After-Tax Cost of Debt	+	Proportion of Equity	x	Cost of Equity	+	After-Tax Cost of Credit Enhancement, or
WACC(AS)	=	$(1\text{-}Eq\%_{as})$	x	$(1\text{-}T)\ k_{as}$	+	$Eq\%_{as}$	x	k_e	+	$(1\text{-}T)\ k_{ce}$

[16] The beta for the average financial institution is approximately one. For example, the estimated beta for the Standard & Poor's Financial Average of 50 banks and insurance companies is 1.00, and the beta for the NYSE Financial Index is 0.96

[17] Source: *Stocks, Bonds, Bills and Inflation: 1990 Yearbook*, Ibbotson Associates, Inc.

[18] For more information, see *The Financial Executive's Guide to the Cost of Capital*, Peter B. Blanton, Eric B. Lindenberg and Kevin L. Thatcher, Salomon Brothers Inc, June 1990.

• **Cost of Capital Savings.** The savings in cost from asset securitization is WACC(bs) - WACC(as). Thus,

$$\text{WACC Savings} = (1\text{-}Eq\%_{bs}) \times (1\text{-}T) \times k_d + Eq\%_{bs} \times k_e - (1\text{-}Eq\%_{as}) \times (1\text{-}T) \times k_{as} + Eq\%_{as} \times k_e + (1\text{-}T) \times k_{ce}$$

The above expression can be reduced to the following:

$$\text{WACC Savings} = (1\text{-}T) \times (1\text{-}Eq\%_{bs}) \times (k_d\text{-}k_{as}) + (Eq\%_{bs}\text{-}Eq\%_{as}) \times (k_e\text{-}(1\text{-}T) \times k_{as}) - (1\text{-}T) \times k_{ce}$$

Intuitively, we can think of this as,

WACC Savings	=	After-Tax Savings in the Debt Rate	+	Savings from Releasing Equity Capital	-	Cost of Credit Enhancement

Note that the savings from releasing equity are simply the amount of equity capital released, multiplied by the equity cost of capital premium over the cost of debt. The reason that the reduction in equity capital is multiplied by the difference in cost between equity and debt is that asset securitization does not actually reduce the amount of funds to be raised; it merely replaces some of the more expensive equity with less expensive debt.

• **Impact of Foreign Interest Allocation Rules.** Our result can be extended to reflect any savings from avoiding foreign interest allocation problems. If a particular company effectively is unable to deduct F% of its interest expense because of interest allocation rules, the total WACC savings are as follows:

$$\text{WACC Savings} = (1\text{-}T) \times (1\text{-}Eq\%_{bs}) \times (k_d\text{-}k_{as}) + (1\text{-}Eq\%_{bs}) \times F\% \times T \times k_d + (Eq\%_{bs}\text{-}Eq\%_{as}) \times (k_e - (1\text{-}T) \times k_{as}) - (1\text{-}T) \times k_{ce}$$

Or intuitively,

WACC Savings	=	After-Tax Savings in the Debt Rate	+	Savings from Avoiding Interest Allocation Problem	+	Savings from Releasing Capital Equity	-	Cost of Credit Enhancement

with,

Savings from Avoiding Interest Allocation Problem	=	Proportion of Debt in Balance Sheet Funding	x	Pct. of Interest Expense Not Deductible	x	Marginal Tax Rate	x	Pretax Cost of Debt

Key for Formulas

k_{as}	Cost of debt using asset securitization.
k_{ce}	Cost of credit enhancement using asset securitization.
k_d	Cost of on-balance-sheet borrowing.
k_e	Cost of equity.
$Eq\%_{as}$	Proportion of equity required to fund assets using asset securitization.
$Eq\%_{bs}$	Proportion of equity required to fund assets using balance sheet financing.
F%	Percentage of interest expense that is not tax deductible under the foreign interest allocation rules.
T	Marginal income tax rate.
WACC(as)	Weighted-average cost of capital of asset securitization funding.
WACC(bs)	Weighted-average cost of capital of balance sheet funding.

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PECO STATEMENT NO. 6

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY FOR ISSUANCE OF A QUALIFIED RATE ORDER UNDER SECTION 2812 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY

OF

JOHN J. GILLEN

Regarding PECO Energy Company's Proposed Sale Of Intangible Transition Property

DIRECT TESTIMONY JOHN J. GILLEN

Q: Please state your name and business address.

A: John J. Gillen, 639 Loyola Avenue, Suite 1800, New Orleans, LA 70113.

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

A: I am employed by Coopers & Lybrand as chairman of the firm's Electric and Gas Industry Program. I also serve as market managing partner of the New Orleans office.

Q: Please describe your educational background.

A: I am a graduate of Widener University and hold a B.S. in Accounting. I am also a Certified Public Accountant in the state of Pennsylvania.

Q: Did you have any work-related experience prior to joining Coopers & Lybrand?

A: Yes. Prior to joining Coopers & Lybrand I spent four years with the Federal Energy Regulatory Commission (FERC) as a field staff audit supervisor.

Q: Please outline your current responsibilities and experience.

A: I currently serve as the partner responsible for several of Coopers & Lybrand's utility clients. My experience also includes advising electric and gas companies and providing counsel on issues in arbitration and litigation, design of special programs for review of internal controls, and matters of regulatory compliance. I have made numerous presentations before industry and regulatory personnel each year and have presented expert testimony on a variety of matters before regulatory commissions. I am a contributing author to *Montgomery's Auditing* and currently serve as the chairman of the American Institute of Certified Public Accountants Public Utilities Committee. As the chairman of Coopers & Lybrand's Electric and Gas Industry Program, I am responsible for the overall direction of services to clients in the electric and gas industries throughout the country. This responsibility requires me to advise partners of the Firm in accounting and regulatory matters relating to public utilities and independent power companies; to participate in Coopers & Lybrand's research efforts related to accounting, income tax and regulatory issues impacting utilities and independent power companies; and to coordinate industry communication, training programs and conferences.

Q: Is there any further experience you wish to describe?

A: Yes. In my capacity as chairman of Coopers & Lybrand's Electric and Gas Industry Program and chairman of the AICPA Public Utilities Committee, I have developed and led training sessions before the Securities and Exchange Commission's (SEC) accounting and finance staff, and the FERC's audit staff. I led a team of authors of a white paper entitled, *Going Off 71*, published by Coopers & Lybrand in September 1995 to assist rate-regulated enterprises in assessing the continued applicability of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standard No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71) to their financial statements. I also met recently with the chief accountant of the SEC to discuss the continued application of FAS 71 to rate-regulated enterprises and have been asked to moderate a similar discussion with members of the FASB and its staff.

Q: What is the purpose of your testimony in the proceeding?

A: I will discuss several of the accounting and tax issues which result from the passage of the Electricity Generation Customer Choice and Competition Act (the "Competition Act") and the anticipated sale by PECO Energy Company (PECO) of its Intangible Transition Property (ITP).

Q: Are you familiar with PECO's financial statements?

A: Yes, from 1988 to 1990 I was the audit manager on the PECO account. I have served as the audit partner or concurring partner continuously since 1992.

Q: Please describe the current application of Generally Accepted Accounting Principles (GAAP) at PECO.

A: The primary statement which has historically governed the application of GAAP for PECO is FAS 71. This statement applies to general purpose financial statements of a rate-regulated enterprise that meets three criteria. The enterprise must have rates that: (1) are approved by the regulator; (2) are cost-based; and (3) can be charged to and collected from customers. These criteria may also be applied to separable portions of a utility's business, such as the generation of transmission functions, or to specific classes of customer.

Q: Please explain how FAS 71 relates to the concept of a "regulatory asset."

A: Under FAS 71, a rate-regulated entity may capitalize costs that would otherwise be charged to expense if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. The amount thus capitalized is a "regulatory asset."

Q: What happens to unrecovered regulatory assets if an enterprise no longer meets the criteria for the application of FAS 71?

A: If it is determined that FAS 71 no longer applies to a formerly rate-regulated enterprise, then the treatment of regulatory assets and regulatory liabilities is dictated by FASB Statement of Financial Accounting Standards No. 101, *Regulated Industries - Accounting for the Discontinuance of the Application of FASB Statement No. 71* (FAS 101). Under these circumstances, FAS 101 requires regulatory assets and liabilities to be written-off "... unless the right to receive payment of the obligation or the obligation to pay exists as a result of past events or transactions and regardless of future transactions." In addition, FAS 101 requires the formerly rate-regulated enterprise to consider the extent to which its remaining assets are impaired and to make appropriate write-offs based upon the criteria set forth in FASB Statement of Accounting Standards No. 121, *Accounting for the*

Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of (FAS 121).

Q: Does the Competition Act have implications for the continued application of FAS 71 for PECO?

A: Yes, it does. The Competition Act requires the introduction of competition for the generation function by January 1, 1999 and, as a result, the generation portion of PECO's business will not meet the criteria for the continued application of FAS 71. However, the Competition Act also authorizes the Pennsylvania Public Utility Commission (PUC) to determine the level of transition or stranded costs for each jurisdictional electric utility and provide for the recovery of such costs through a non-bypassable Competitive Transition Charge (CTC). The Competition Act also creates the legal framework to permit electric utilities to securitize their stranded costs, in which case recovery occurs through an Intangible Transition Charge (ITC). Given these provisions of the Competition Act, regulatory assets recorded by PECO that are specifically designated for recovery under the CTC or ITC would not have to be written-off immediately.

Q: Based upon the availability of the CTC and ITC, what accounting entries would likely be required to record the effects of the Competition Act?

A: PECO will be required to record certain obligations that are currently unrecorded. For example, in accordance with prevailing utility industry accounting conventions, unfunded decommissioning obligations are not typically recorded. As a result of the passage of the Competition Act, these amounts will be recorded as liabilities. To the extent that the funding of these liabilities is probable of future collection through the CTC or ITC, the charge associated with these liabilities may be accounted for as ITP and deferred, thereby avoiding an immediate write-off.

Additionally, certain generating assets may now be considered impaired due to future competitive generation pricing. To the extent these uneconomical generating fixed assets are identified for future collection through the CTC or ITC in the Company's PUC-approved restructuring plan, they need not be written-off as impaired pursuant to FAS No. 121 and the associated expense may be deferred as ITP.

Although I believe that the deferral of these costs as ITP is appropriate, I understand the SEC staff is examining the appropriate accounting in this area. As a result, PECO will need to seek approval for deferral of these charges as ITP from the SEC.

Q: Have you reviewed the proposed journal entries set forth in PECO Exhibits 2 and 3?

A: Yes, I have reviewed the proposed journal entries. Based upon the information provided by PECO and subject to the SEC's concurrence with the proposed deferrals and "true sale" treatment of ITP, the journal entries are reasonable, conform to GAAP and would fairly present, in all material respects, the financial impact upon PECO of the Competition Act and the proposed securitization.

Q: Are you familiar with the plan for PECO to sell its ITP as part of the securitization process described by Messrs. Mitchell and Hiller?

A: Yes. I have read the testimony of Mr. Mitchell and Mr. Hiller and am familiar with PECO's proposed securitization plan.

Q: What is your understanding of the nature of the assets to be sold in the proposed securitization?

A: ITP is defined as the property right created by the Competition Act representing the irrevocable right of the electric utility, or an assignee, to receive, through the ITC, amounts sufficient to recover all of its Qualified Transition Expenses to the extent determined by the PUC in accordance with the terms of the Competition Act. The ITC is a non-bypassable charge to be imposed on customer bills by the utility or its successor.

Q: What do you believe is the relevant accounting standard related to the proposed accounting for the sale of ITP?

A: The analysis of this issue begins with Statement of Financial Accounting Standards No. 125, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities* (FAS 125), which the FASB issued in June of 1996 to become effective January 1, 1997. As its title indicates, FAS 125 applies to transfers of "Financial Assets."

Accordingly, the threshold issue is whether ITP is considered a financial asset for purposes of FAS No. 125.

Q: What factors will affect the determination of whether the ITP is considered a "Financial Asset?"

A: FASB Statement of Financial Accounting Standards 107 *Disclosures about Fair Value of Financial Instruments* (FAS 107) and FASB Statement of Financial Accounting Standards 105 *Disclosure of Information about Financial Instruments with Off-Balance-Sheet Risk and Financial Instruments with Concentrations of Credit Risk* (FAS 105) contain definitions and examples that are used to define the nature of financial assets. Under FAS 107 and 105, these definitions would not comprehend ITP. However, these definitions should not be read in isolation. FAS 125 contains guidance for defining financial assets. Specifically, paragraph 114 distinguishes financial and nonfinancial assets on the basis that the latter have "operational value," which can be realized or enhanced only by the application of "managerial skill." Paragraph 114 further provides:

> In contrast, financial assets have no operational use. They may facilitate operations, and financial assets may be the principal "product" offered by some entities. However, the promise embodied in a financial asset is governed by contract. Once the contract is established, management skill plays a limited role in the entity's ability to realize the value of the instrument.

Q: Given the characteristics of the ITC and the legal framework created by the Competition Act, would ITP be considered a financial asset for the purposes of FAS 125?

A: A Qualified Rate Order issued by the Commission may be viewed under GAAP as creating a right on the part of the utility to receive cash from current and future customers in its service territory, as a group, as the ITC is billed and collected. That right arises from the irrevocable promise of the Pennsylvania legislature, as implemented by irrevocable formal action of the Commission, to establish and enforce a non-bypassable charge for the recovery of ITP. Further, management skill in the continued operation of the Company will play a limited role in PECO's ability to realize the value of the ITP. In light of these factors, the ITP would appear to satisfy the criteria for financial assets under FAS 125. In that event FAS 125 would be the relevant accounting pronouncement to determine whether the proposed transfer of ITC to a special purpose entity would qualify as a true sale for financial reporting purposes. I should note, however, that the SEC and the FASB are currently assessing whether assets similar in nature to the ITP are considered financial assets for the purposes of FAS 125. Because of the relatively recent issuance and effectiveness of FAS 125, neither the SEC nor the FASB has yet made a definitive determination of this issue.

Q: Under FAS 125, what conditions must be met in order to account for the proposed securitization of ITP, by a special purpose entity, as a sale of financial assets?

A: Paragraph 9 of FAS 125 provides that a transaction will be accounted for as a sale if the transferor "surrenders control" over financial assets and receives in exchange consideration other than a beneficial interest in the transferred assets. The "surrender of control" is determined by reference to the following criteria in paragraph 9:

a. The transferred assets have been isolated from the transferor and its creditors, even in bankruptcy or other receivership;

b. The transferee obtains the right, free of conditions, to pledge or exchange the transferred assets; or the transferee is a qualifying special purpose entity where holders of beneficial interests in that entity have the right, free of conditions, to pledge or exchange those interests; and

c. The transferor does not maintain effective control over the transferred assets.

Q: Would PECO's proposal to securitize its stranded costs through the sale of ITP satisfy FAS 125's criteria for treatment as a true sale?

A: The statutory provisions added by the Competition Act create a legal framework that makes it possible to meet the conditions of a true sale. Additionally, based upon my review of Messrs. Mitchell's and Hiller's testimony, it appears that the general structure of the proposed transaction is consistent with the sale criteria set forth in FAS 125. Of course, the ultimate determination as to whether those criteria are met is also dependent on the specific terms, conditions and representations contained in the sales documents. Consequently, those documents would be carefully reviewed before a final opinion could be rendered on this matter.

Moreover, PECO will need to request written concurrence with the proposed accounting for this transaction from the SEC. The form of this request would be a letter describing the transaction and indicating that it has been discussed with its independent accountants, who likewise must concur with the accounting treatment. The SEC must then respond that it will not object to the proposed accounting. It is possible that the SEC might object or object as to portions of the ITP as a financial asset. Normally, the SEC will respond soon enough so that the transaction will be properly reflected in the Company's next filing with the SEC. In this circumstance it is likely the SEC will be able to respond quickly because a similar request has been made by another SEC registrant.

Q: Is there any accounting guidance other than FAS 125 that could provide a basis for treating the proposed securitization as a sale for financial reporting purposes?

A: Financial Accounting Standards Board Emerging Issue Task Force (EITF) Issue No. 88-18, *Sales of Future Revenues* has been referred to in prior securitization transactions as the relevant accounting pronouncement. It sets forth several criteria which individually create a rebuttable presumption that the proceeds from a transaction be classified as debt. Of course, the ultimate determination as to whether those criteria are met is also dependent on the specific terms, conditions and representations contained in the sales documents. Consequently, those documents would be carefully reviewed before a final opinion could be rendered on this matter. Moreover, the SEC would also have to give its approval, as described above, for PECO to account for the proposed transaction as a sale under EITF 88-18.

Q: Turning to the issue of income tax accounting, would you explain the tax consequences of the proposed transaction?

A: In order for the proposed transaction to provide benefits to PECO and its customers, it must be regarded as a sale for book purposes but <u>not</u> for tax purposes. A sale for tax purposes would be an income recognition event that would trigger an income tax liability in the year of the sale. Consequently, the desired treatment for tax purposes is to have the transaction regarded as a financing and not as a sale.

Q: Is there is a sound basis, under applicable federal income tax regulations and similar authority, for categorizing the proposed transaction as a financing for income tax purposes?

A: If the proposed transaction is treated as a sale for accounting purposes, then case law involving a taxpayer's transfer of the right to receive future income streams supports a favorable ruling by the Internal Revenue Service (IRS) that the securitization of the Intangible Transition Property would more closely resemble a loan than a sale. In the event the securitization is deemed to fall within the purview of EITF 88-18, it would likewise be necessary for the IRS to issue a favorable ruling on the transaction.

Q: What action is PECO taking to receive favorable tax treatment of the proposed transaction?

A: Tax counsel is currently preparing for PECO a private letter ruling request, describing the transaction which will be submitted to the Rulings Branch of the IRS National Office within the next few weeks. The request will ask the IRS to rule that the securitization of ITP will be treated as a loan for federal income tax purposes. A favorable ruling in this respect will be binding on the IRS provided that the request contains complete and correct disclosure of all material facts relating to the transaction.

Q: What is the expected outcome and timing for the IRS to rule on PECO's request?

A: The IRS is not required to rule on the tax characterization of the transaction. Given the magnitude of the transaction and the potential tax revenue at stake for the government, the IRS may decline to rule on this issue. In addition, there is no express time limit in which the IRS must render its ruling; however, PECO will be requesting expeditious handling of the request, which should result in a more timely resolution of the issue. In the event the IRS refuses to rule on this issue, it is possible that PECO would be able to rely on an opinion of its tax counsel.

Q: Does this conclude your testimony?

A: Yes.

PECO STATEMENT NO. 7

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY FOR ISSUANCE OF A QUALIFIED RATE ORDER UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY OF

JOHN F. BUSTARD

Regarding Market Price Analyses

TABLE OF CONTENTS

DIRECT TESTIMONY OF JOHN F. BUSTARD

I. QUALIFICATIONS

Q. ***Please state your name and business address for the record.***

A. John F. Bustard, 2301 Market Street, Philadelphia, Pennsylvania, 19103.

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

A. I am a Senior Engineer in the Bulk Power Enterprises group of PECO Energy Company ("PECO" or the Company).

Q. **What is your educational background?**

A. I graduated in 1968 from Lehigh University with a Bachelor of Science in Electrical Engineering and in 1973 from the University of Illinois with a Master of Science in Electrical Engineering specializing in Power Systems.

Q. **Are you professionally certified?**

A. I am a registered professional engineer in the Commonwealth of Pennsylvania, PE-023180-E.

Q. **Please summarize your experience with PECO.**

A. I joined PECO in 1973 as an Engineer in the System Planning Division. For 15 months in 1976-1977, I was a Project Manager with the Electric Power Research Institute, on loan from PECO. In 1986 I was promoted to Senior Engineer and in 1989 to Supervising

Engineer in System Planning. In 1993 I was named a Manager in Supply and Demand Planning. In 1994, my team was moved to the Business Planning and Financial Analysis section in the Consumer Energy Services group. In 1995, I transferred to Transmission Management within the Bulk Power Enterprises group as a Senior Engineer.

Q. **What are your responsibilities in your current position?**

A. I am responsible for PECO's analysis of generation operation and costs while explicitly recognizing transmission constraints. Also, I am responsible for developing the information contained in PECO's Open Access Same-Time Information System (OASIS), the internet-based system providing transmission price and availability information that complies with Federal Energy Regulatory Commission(FERC) Order 889.

Q. **What previous experience at PECO qualifies you to make estimates of market revenue?**

A. Throughout my career at PECO, I have determined costs and benefits associated with PECO's generation and transmission and the cost of serving load. I was responsible for preparation of PECO Energy's first Integrated Resource Plan, first Coal Upgrade Report, providing avoided costs to potential non-utility generators, and planning for Demand Side Management programs. I developed costs and benefits and testified before the Commission on the prudence of PECO's Phase I compliance with the 1990 Clean Air Act Amendments.

Q. **Have you participated in other related activities?**

A. Yes. I was an Adjunct Assistant Professor at Drexel University from 1973 to 1987 teaching undergraduate and graduate courses on Power Systems, Power System Economics, Power System Dynamics and Computer Applications to Power Systems.

II. INTRODUCTION AND SUMMARY

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

A. The purpose of my testimony is to present the results of several analyses, performed at PECO's request, to project the market price and corresponding market revenues which each of PECO's generating units could reasonably be expected to command in a competitive generation market commencing January 1, 1999. A list of PECO's generating units is presented by Mr. Cohn in Exhibit ABC-2. In the process of doing so, I will discuss the framework for these analyses and will identify the major factors that will determine the market value of those facilities.

Q. **Why did PECO initiate these market price analyses?**

A. As explained by Mr. Hill in his testimony, to calculate PECO's stranded costs it is necessary to assign a market value to its existing generation units. Their market value, in turn, will be a function of how frequently they operate, what price can be obtained for their output and their capacity to operate when needed.

Q. **Please describe, in general terms, the market price studies that were performed at PECO's behest.**

A. Three separate studies were conducted. The first was performed by the EDS Utilities Division, utilizing its Power Market Decision Analysis Model (PMDAM). The second study was conducted by William H. Hieronymus of Putnam, Hayes & Bartlett (PHB). Dr. Hieronymus presents the results of his analysis in his direct testimony and supporting exhibits. The third market price study was performed by ICF Resources Inc. (ICF), and is described by Dr. Bangalore S. Venkateshwara in his testimony.

Q. **Why did PECO procure multiple market price estimates?**

A. PECO submitted the results of several expert analyses in an effort to develop a range of reasonable expectations for the Commission's consideration.

Q. **Please summarize your conclusions regarding PECO's market price analyses.**

A. The results of the studies conducted by EDS, PHB and ICF are set forth in Exhibits JFB-1 through JFB-3 and are described in the following sections of my testimony.

III. MARKET PRICE, MARKET REVENUE AND MARKET REVENUE NET OF FUEL

Q. **What is the market price of PECO's generation?**

A. The market price PECO can expect to receive for its generation will be a weighted market price. The annual prices for each of the three market clearing price analyses are set forth in Exhibit JFB-1.

Q. What does PECO's weighted market price represent?

A. The weighted price takes into account the variation in expected market prices among different generating units. A particular unit's market price multiplied by its megawatt (MW) output during each hour summed over all hours of a year equals its market revenue for its energy. Market revenue for a unit's capacity equals its net rating multiplied by the market price of capacity. The sum of the market revenues for all generating facilities divided by the sum of the megawatt hours (MWh) output of all such units equals the weighted average price.

Q. What is PECO's estimate of the market revenue to be produced by its generating facilities?

A. PECO's total market revenue for each of the three analyses is set forth in Exhibit JFB-2.

Q. What do you estimate to be the market revenue net of fuel of PECO's generating facilities?

A. The value of PECO's generating facilities, as defined in terms of market revenue less fuel cost, for each of the three analyses, is set forth in Exhibit JFB-3.

IV. BASIS FOR DETERMINING MARKET PRICE

Q. In developing the market price estimates, what assumptions were made regarding the market in which PECO's generating facilities would compete?

A. All of PECO's generating units are located in the Mid Atlantic Area Council (MAAC), which geographically is the same as the Pennsylvania-New Jersey-Maryland (PJM) Interconnection. However, FERC initiatives, including Order 888, have opened up the transmission system to all wholesale buyers and sellers. As a result, the PJM Interconnection is now only a part of a much larger power market. Consequently, all three studies reflect the fact that PECO's generation will be competing for sales not only within the PJM Interconnection, but also over a much larger area, including the New York and New England Power Pools and the Midwest and Southeastern states.

Q. **How will PECO and other participants sell their generation into a competitive energy market?**

A. For electricity, like other competitive markets, bidders will sell at the highest price they can expect to receive for their product, subject to not selling below their cost. Therefore, an equilibrium of supply and demand exists at the marginal cost of producing the product.

Q. **At what price will the energy market clear?**

A. For the electric energy market, the equilibrium of supply and demand must be maintained on an instantaneous basis. Market participants will have quick feedback on the market price at any time. With such feedback, the market can be expected to clear at the highest marginal cost generating unit operating in any hour. This will occur whether the market evolves into a bilateral market or a spot market. Dr. Hieronymus further discusses bilateral and spot markets in his testimony. Therefore, because the market will clear at the hourly marginal cost, and because price in the spot market represents price in a bilateral market, an assessment of future market prices can be made using the same production cost estimating tools which utilities have been using for years.

Q. **You previously indicated that the studies conducted by EDS, PHB and ICF each calculated market prices on an individual generating unit basis. Why was this necessary?**

A. The varying demand for electricity means that during all but a few hours part of the generation supply will not operate. Economic dispatching of supply has historically been done to minimize costs. I expect the objective under competition of maximizing net market value to cause units to be dispatched in a similar way as they would have under economic dispatch. Therefore, the market price for high cost units is not the yearly average of all hourly prices, but is based on the market price during the subset of hours that they operate.

Q. **Can you give an example?**

A. Yes. This is vital to a correct analysis. Let me compare the energy portion of the market price for a low and a high cost unit. A unit with a low operating cost such as Limerick will be economic to dispatch during all but a few hours of the year. ICF projects Limerick's all hours market price for energy to be $21.1/MWh in 1999. However when units have operating costs higher than the market price they will not operate. Higher cost units will operate only during the higher price hours of the year. ICF projects that Eddystone Units 3&4 will have an operating cost of $25.6/MWh in 1999. That cost is less than market price only 5% of the year. During that 5% of the year, the average market price is $29.3/MWh.

Q. **Is this the method you used to determine the weighted market price?**

A. Yes. If I perform a similar analysis to get the market price that applies to each generator, sum to get total market revenue for all generators and divide by the total output, I get the weighted market price.

Q. ***Is this weighted market price as such used as an input to the stranded investment determination in Mr. Hill's testimony?***

No. The market prices and associated market revenue for individual generators drive the analysis. The weighted market price is presented as a way of summarizing the prices of the individual generators.

Q. **How does this weighted market price compare to an all hours market price?**

A. The annual average of the market prices for all hours for each of the three market price analyses are set forth in Exhibit JFB-4. Weighted market prices as set forth in Exhibit JFB-1 are higher than all hours prices.

Q. **What other factors, if any, affect the market price of a generating unit?**

A. When the transmission system is constrained, market price is also a function of the location of a particular generating unit within the electric system. When the transmission system cannot reliably transmit electric energy with only the lowest bidding generators operating, the system operator will accept bids that are above the unconstrained market clearing price. The system operator will do this in a way that minimizes the amount of constraint control but, at times, the most efficient way of operating the system will require constraint control payments. The calculation of market price must account for bids accepted because of transmission system effects. All three market price analyses (EDS, PHB and ICF) take this into consideration.

Q. **Besides energy, what else is included in the market price?**

A. The need of an electric system to instantaneously match supply and demand even under quickly changing conditions such as load increases or unit outages requires that adequate backup supply be available at all times. The Electric Competition Act recognizes this fact by requiring generation suppliers to maintain adequate reserve margins to keep supply available in the event of unit outages. Therefore, the market price of an individual generating unit must include the market price of its capacity or ability to supply power even when not actually supplying energy.

Q. **How was this market price of capacity calculated?**

A. Each expert determined the market price of capacity in $/kW-year and then determined capacity revenue based on the rating of each generator.

Q. **What use do you make of the market revenue from capacity?**

A. I add the market revenue from capacity to the market revenue of energy to determine the total revenue shown in Exhibit JFB-2. The weighted market price of Exhibit JFB-1 includes the market revenue from capacity.

V. KEY FACTORS THAT WILL DRIVE FUTURE MARKET PRICES

Q. **What are the key factors that will drive the future market price of electricity?**

A. There are many factors that will affect the future price of electricity. The three that stand out, and which I will discuss, are (1) fossil fuel prices, (2) consumption levels and (3) customer reliability requirements.

Q. **What fossil fuel price projections were utilized by the various consultants in their market price analyses?**

A. EDS and PHB used the latest (October 1996) DRI/McGraw-Hill forecast of coal, oil and gas prices for the Middle Atlantic region independently developed by DRI. Those estimates are set forth in tabular and graphic form in Exhibit JFB-5. Dr. Venkateshwara utilized a fossil fuel price forecast independently developed by ICF.

Q. **How did the consultants estimate future electric consumption levels?**

A. All three relied on the annual load growth forecast submitted by MAAC to the North American Electric Reliability Council (NERC) and the Energy Information Agency (EIA) on April 1, 1996, the results of which are presented in Exhibit JFB-6. As shown, that forecast extends only through 2005. Consequently, for purposes of estimating market prices after that date, load was projected to continue to grow at a constant rate equal to that projected, on average, for the 2003-2005 period. For other regions of North America, the consultants relied on data submitted to EIA by those other regions.

Q. Regarding the third factor, what projections were made with respect to future reliability requirements?

A. For purposes of their analyses, the consultants projected that MAAC/PJM would adhere to an 18% reserve margin standard. Although this figure is below the 20% margin established for the 1998-99 planning period (i.e. the anticipated first year of widespread retail competition), the recent trend in the required reserve margin has been downward largely because of reduced unit outage time. In addition, I would expect new units to be smaller than the average size unit currently on the system, thereby further lowering the reserves needed to maintain a given level of reliability. MAAC reaches an 18% reserve margin in 2001 as set forth in Exhibit JFB-7.

Q. Apart from the three fundamental factors which you just discussed, what other factors were examined to develop future market price projections for PECO's various generating units?

A. Each of the three analyses incorporated somewhat different views on other factors that affect market price. Examples of these other factors are the type of new generation added over time, retirement of older generation, variable O&M costs of generation, changes in availability and efficiency of generation, fuel switching and strategies for meeting emission standards. Transmission factors which affect the market price of generation are transmission wheeling costs, transmission constraints and transmission expansion to alleviate constraints and ancillary services.

VI. EDS MARKET PRICE PROJECTIONS

Q. **Please describe the market price projections developed by EDS.**

A. The results of the EDS analysis are included in the data set forth in Exhibits JFB-1, JFB-2 and JFB-3. As shown in Exhibit JFB-1, EDS projects a weighted market price for PECO generation at January 1, 1999 of $29.2 per MWh and increasing prices after 1999. Similar projections of market revenues and net market revenues (net of fuel costs) may be found in Exhibits JFB-2 and JFB-3, respectively.

Q. **Why did you rely on EDS for projections of market price rather than your own work?**

A. Experts within PECO do not have a long-range database available to model market price beyond the next few years.

Q. **What makes EDS qualified to make projections of market price?**

A. EDS has the expertise and data to determine market price. They provide estimates of market price to over 15 clients across the USA Those clients include entities on all sides of the electricity market including power marketers and independent power producers.

Q. **What was the basis of the EDS projection of market price?**

A. Factors affecting the price projections are set forth in Exhibit JFB-8.

Q. How did EDS develop its projections?

A. As I mentioned previously, EDS utilizes its own PMDAM model, the principal features of which are described in Exhibit JFB-9. EDS' data base is quite comprehensive and incorporates generation, transmission and load data from all of MAAC/PJM, the East Central Area Reliability Coordination Agreement (ECAR), which lies to the west of MAAC, and the Southeastern Electric Reliability Council (SERC), which lies to the south.

Q. How does EDS treat differences in market price by location?

A. EDS models companies with separate transmission tariffs each as a node. Transfer of energy between nodes is charged the firm or non-firm transmission rate and transmission loss factor. PJM is represented as having one transmission tariff and is one node. Differences in prices are represented between different nodes but all prices within PJM are the same.

Q. How does EDS estimate the price of capacity?

A. EDS estimates that capacity will be freely traded in a deregulated capacity market. EDS further recognizes that each hour's need for capacity can be supplied from anywhere in the interconnection subject to available transmission transfer capability and to the cost of firm transmission service. The price of capacity is capped at the cost of a new unit, but can be expected to be less most of the time because capacity will be available from other regions.

Q. **What years did EDS project?**

A. EDS projected market price annually through 2010. To be consistent with the other consultants, I determined that beyond 2010, market price would escalate from the 2010 prices at the rate of natural gas escalation.

Q. **What do you project the market price to be beyond 2015?**

A. Beyond 2015, I project both market price and fuel costs to increase at the same 3.5% per year rate as the DRI/McGraw Hill projected change in the GDP deflator. This is reasonable given the uncertainty of projecting market trends 18 years in the future.

Q. **How do the EDS findings compare to the market price projections developed by PHB and ICF?**

A. The results of all three market price analyses are summarized in Exhibit JFB-1. As can be seen, the EDS market price projections are slightly higher than the values developed by PHB and slightly lower than the figures presented by ICF. Similar comparisons of market revenues and net market revenues appear in Exhibits JFB-2 and JFB-3.

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

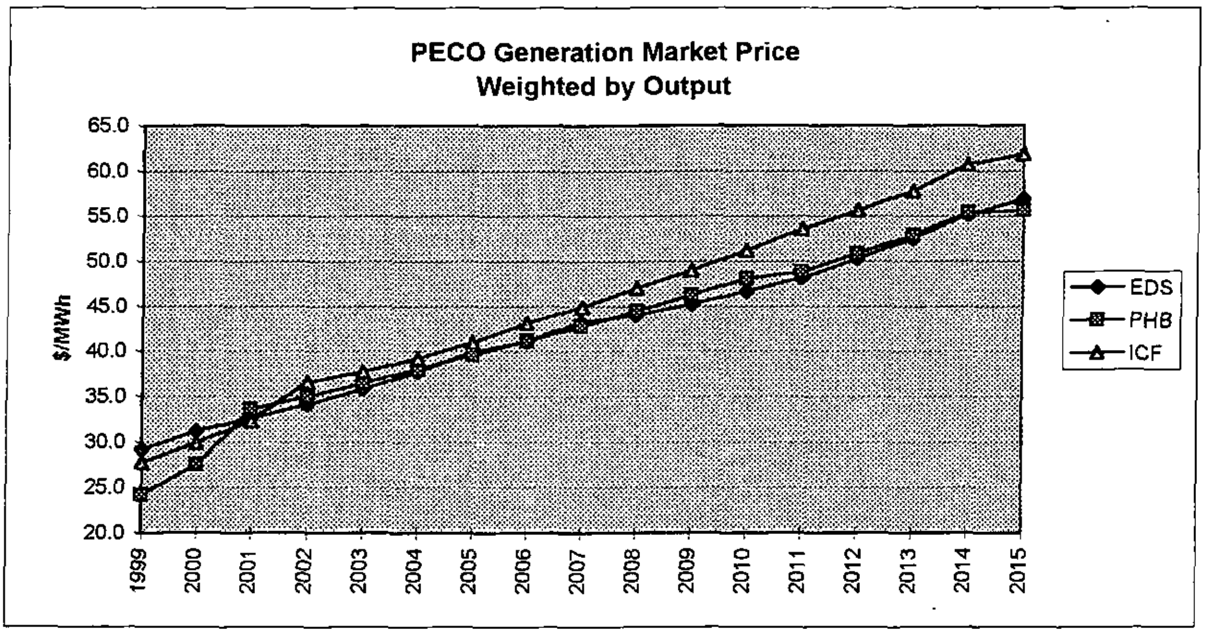
A. Yes.

PECO Generation Market Price

Weighted by Output (1)

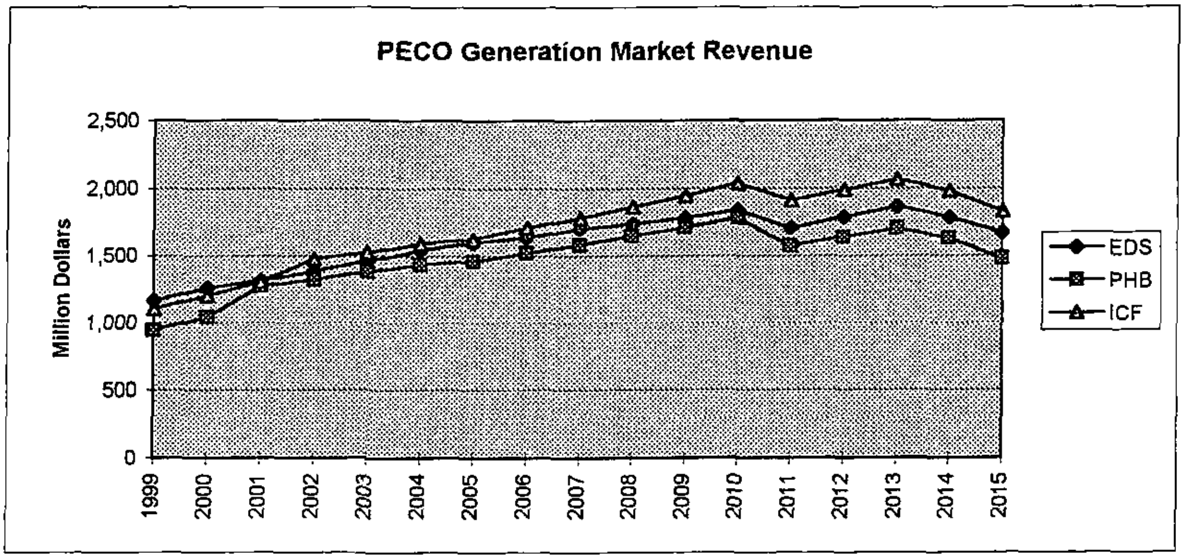
	$/MWh		
	EDS	PHB	ICF
1999	29.2	24.2	27.7
2000	31.2	27.5	29.9
2001	32.6	33.6	32.4
2002	34.1	35.0	36.6
2003	35.8	36.5	37.7
2004	37.7	38.0	39.2
2005	40.0	39.6	41.0
2006	41.1	41.1	43.1
2007	43.2	42.8	44.9
2008	44.0	44.4	47.0
2009	45.2	46.2	48.9
2010	46.7	48.0	51.2
2011	48.1	48.8	53.5
2012	50.2	50.8	55.6
2013	52.5	52.8	57.8
2014	55.1	55.4	60.7
2015	56.8	55.6	61.9

(1) - Weighted market price is the sum of market revenues for each PECO generating unit divided by the total output from all PECO generating units



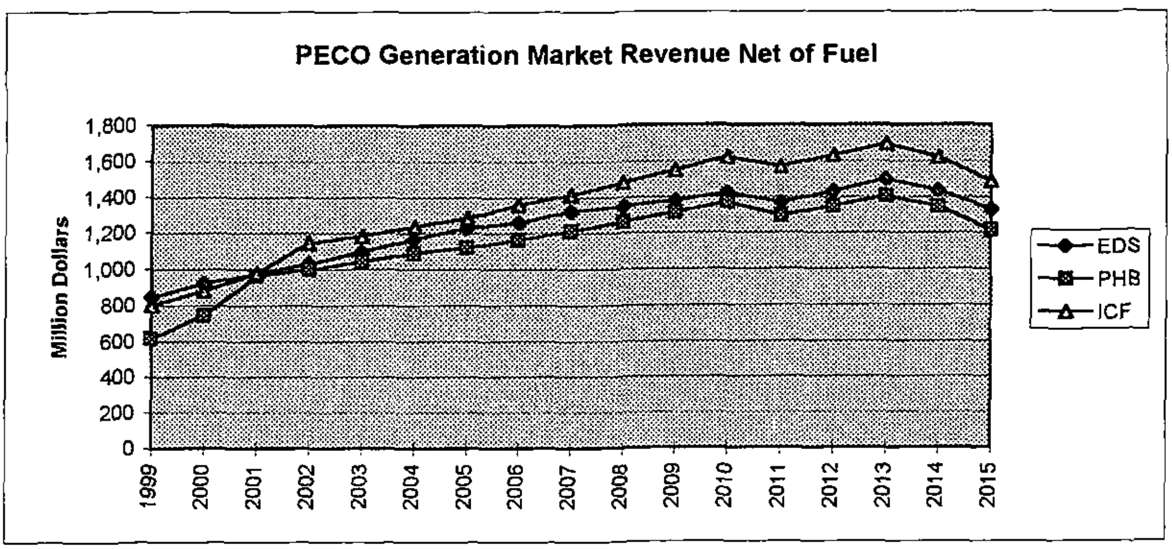
PECO Generation Market Revenue

	Million Dollars		
	EDS	PHB	ICF
1999	1,165	944	1,103
2000	1,255	1,043	1,201
2001	1,313	1,271	1,303
2002	1,382	1,323	1,477
2003	1,459	1,378	1,526
2004	1,541	1,435	1,587
2005	1,598	1,459	1,624
2006	1,630	1,518	1,711
2007	1,700	1,580	1,781
2008	1,737	1,645	1,864
2009	1,782	1,712	1,944
2010	1,838	1,781	2,038
2011	1,707	1,571	1,912
2012	1,783	1,635	1,988
2013	1,862	1,702	2,064
2014	1,787	1,627	1,980
2015	1,667	1,477	1,827



PECO Generation Market Revenue Net of Fuel

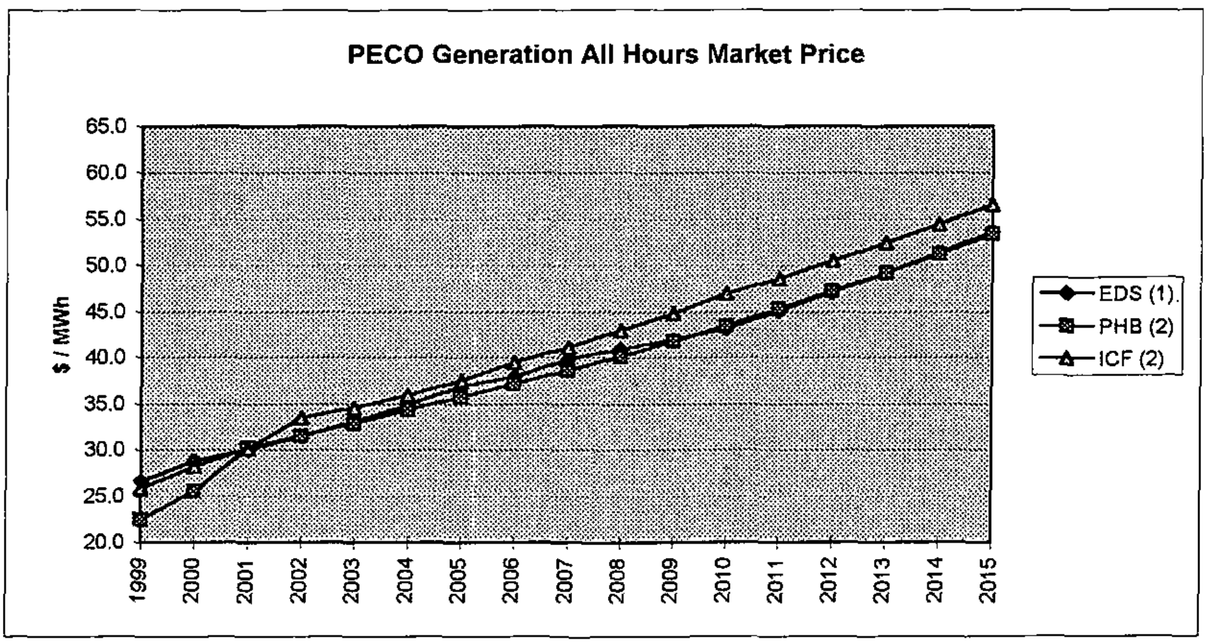
	Million Dollars		
	EDS	PHB	ICF
1999	844	617	801
2000	922	742	880
2001	972	961	978
2002	1,031	1,001	1,144
2003	1,094	1,044	1,185
2004	1,165	1,088	1,237
2005	1,228	1,119	1,282
2006	1,256	1,164	1,355
2007	1,322	1,211	1,412
2008	1,346	1,260	1,481
2009	1,378	1,312	1,546
2010	1,421	1,366	1,622
2011	1,366	1,292	1,569
2012	1,430	1,346	1,632
2013	1,497	1,403	1,694
2014	1,434	1,341	1,620
2015	1,329	1,211	1,485



PECO Generation All Hours Market Price

	$/MWh		
	EDS (1)	PHB (2)	ICF (2)
1999	26.6	22.4	25.8
2000	28.8	25.5	28.2
2001	30.0	30.2	30.2
2002	31.5	31.5	33.5
2003	33.0	32.9	34.6
2004	34.8	34.3	35.9
2005	36.9	35.7	37.5
2006	37.9	37.1	39.4
2007	39.8	38.6	41.1
2008	40.9	40.2	43.0
2009	42.0	41.8	44.8
2010	43.2	43.5	46.9
2011	45.1	45.3	48.6
2012	47.1	47.2	50.5
2013	49.2	49.2	52.4
2014	51.4	51.3	54.4
2015	53.6	53.4	56.5

(1) *PECO generation all hours market price*
(2) Limerick market price. Limerick is a close approximation to PECO generation all hours market price because Limerick operates all hours that it is available and is located in eastern PJM.

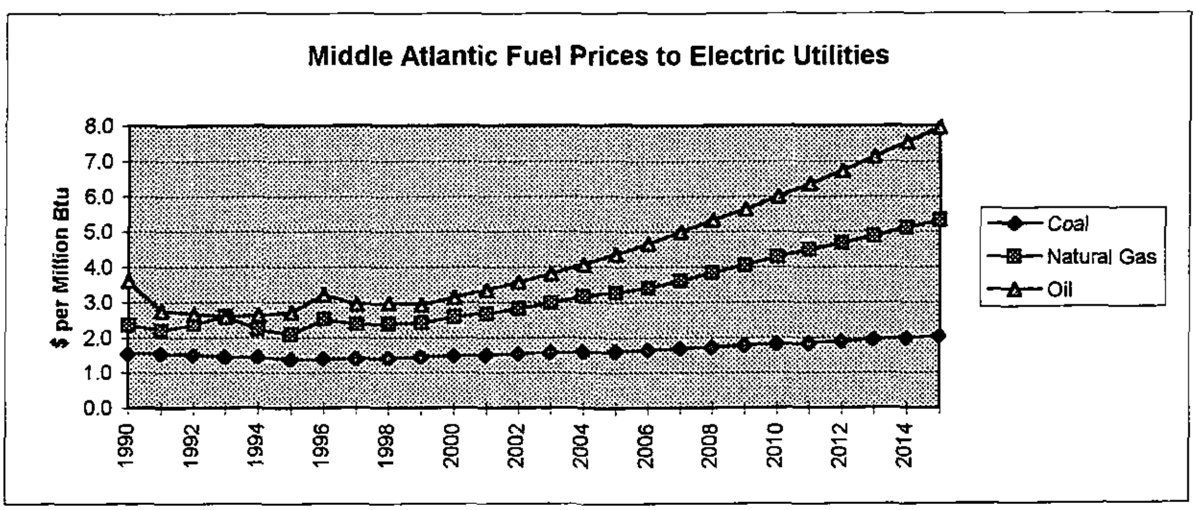


Historical and Expected Fuel Prices

Source: DRI McGraw-Hill World Energy Service U.S.Outlook, Fall/Winter 1996/97 Released Oct 1996

Price of Fuel Delivered to Middle Atlantic Electric Utilities

	(Dollars per Million Btu)		
	Coal	**Natural Gas**	**Oil**
1990	1.55	2.35	3.60
1991	1.55	2.18	2.74
1992	1.50	2.37	2.68
1993	1.46	2.60	2.58
1994	1.45	2.22	2.63
1995	1.39	2.08	2.71
1996	1.40	2.51	3.21
1997	1.40	2.36	2.94
1998	1.41	2.39	2.97
1999	1.45	2.42	2.92
2000	1.49	2.58	3.14
2001	1.51	2.68	3.35
2002	1.54	2.82	3.57
2003	1.57	2.98	3.81
2004	1.60	3.15	4.08
2005	1.62	3.29	4.36
2006	1.65	3.41	4.66
2007	1.69	3.60	4.98
2008	1.73	3.83	5.32
2009	1.77	4.06	5.64
2010	1.82	4.29	5.99
2011	1.83	4.50	6.35
2012	1.88	4.69	6.73
2013	1.93	4.88	7.12
2014	1.98	5.11	7.54
2015	2.03	5.33	7.95



MAAC (PJM) Estimated Net Energy and Peak Demand for 1996 - 2005 and Actual Data for 1990-1995

01 Summer Peak Hour Demand - MW (1)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
47,238	47,923	48,623	49,280	50,044	50,707	51,430	52,082	52,448	53,082

02 Winter Peak Hour Demand - MW (1)

1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06
41,891	42,678	43,301	43,982	44,748	45,309	46,008	46,652	46,672	47,413

03 Net Energy - GWh

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
242,963	246,608	250,390	254,039	257,992	262,238	265,877	269,705	271,905	276,054

01 Summer Peak Hour Demand - MW (1),(2)

1990	1991	1992	1993	1994	1995
42,613	45,937	43,658	46,494	46,019	48,577

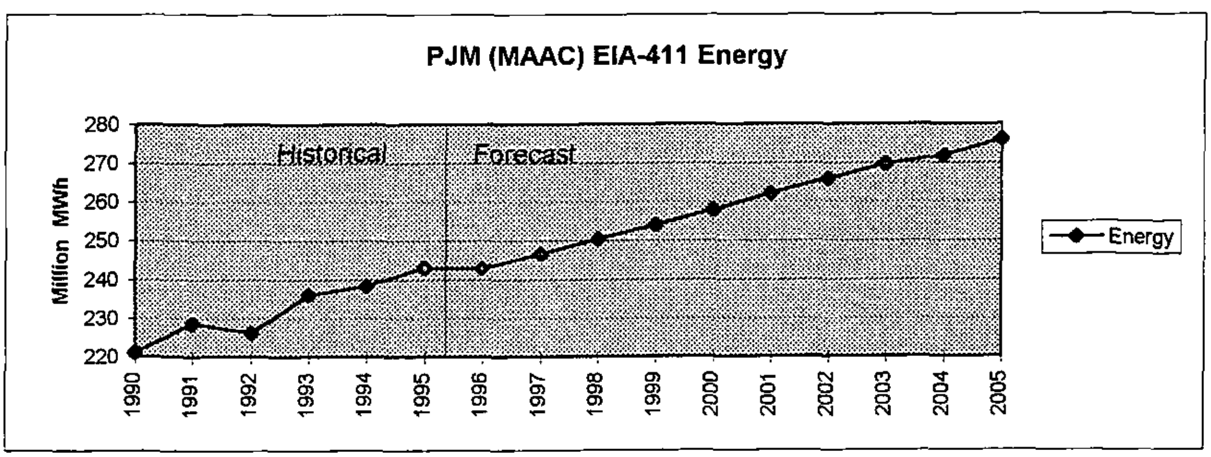
02 Winter Peak Hour Demand - MW (1),(2)

1990	1991	1992	1993	1994	1995
36,551	37,983	37,915	41,406	40,653	40,790

03 Net Energy - GWh

1990	1991	1992	1993	1994	1995
221,099	228,588	226,154	235,980	238,379	243,043

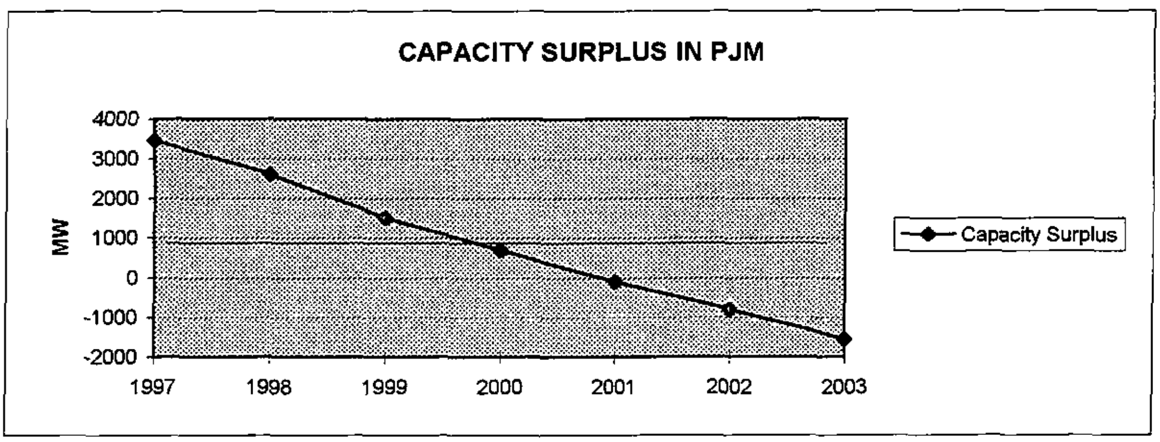
(1) Monthly coincident
(2) Metered peak demand.



PJM LOAD AND CAPACITY FORECAST

MW							
	1997	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
Gross Capacity (1)	57,208	57,056	57,439	57,912	58,454	58,872	59,500
Uncommitted Capacity (2)	0	40	890	1,440	2,140	2,476	3,162
Committed Capacity (3)	57,208	57,016	56,549	56,472	56,314	56,396	56,338
Load with Interruptible Load Implemented (4)	45,554	46,093	46,643	47,257	47,804	48,463	49,050
Required Capacity (5)	53,754	54,390	55,039	55,763	56,409	57,186	57,879
Capacity Surplus (6)	3,454	2,626	1,510	709	-95	-790	-1,541

(1) Expected Load and Capacity Forecast (Summer) - PJM Capacity
(2) Capacity Additions 1995-2010 Summer Capacity (includes all RFPs, bids, and unspecified purchases)
(3) = (1) - (2)
(4) Expected Load and Capacity Forecast (Summer) - PJM Load
(5) = 1.18 * (4) (assumes 18% reserves required to meet "1 in 10" MAAC criterion)
(6) = (3) - (5)



Key Factors Used in EDS Projections

Net Energy For Load

	PJM Energy GWh
1999	251,069
2000	254,922
2005	274,848
2010	295,872

Planning Reserve Margin

	MAAC	Other Regions
1999	18%	15%
2000	18%	15%
2005	18%	15%
2010	18%	15%

Fuel Prices for Typical *Generating Units with* No Season Variation

	Cone-maugh Coal	Eddystone Coal	Delaware *Residual* Oil	*Cromby* Gas	Croydon *Distillate* Oil
	$ per million Btu				
1999	1.23	1.50	2.42	2.42	4.19
2000	1.27	1.54	2.58	2.58	4.50
2005	1.34	1.68	3.29	3.29	6.25
2010	1.51	1.89	4.29	4.29	8.59

Generating Unit Non-Fuel Variable O&M Costs

	Coal	Oil	Gas
	$ per MWh		
1999	2.14	1.07	1.07
2000	2.20	1.10	1.10
2005	2.55	1.27	1.27
2010	3.04	1.52	1.52

Transmission Cost for All Control Areas

	Firm $/kW-month	Non-Firm $/MWh	Losses %
1999	1.60	3.21	3%
2000	1.65	3.29	3%
2005	1.91	3.82	3%
2010	2.28	4.56	3%

Transmission Limits Into PJM

	APS	CEI	VEPCO
	MW		
All Years	2294	306	2700

Exhibit JFB - 9

PMDAM™ MODELING SYSTEM OVERVIEW

Prepared for PECO Energy Company

The information contained within has been prepared for PECO Energy Company in relation to their Market Price Forecast Study performed in December 1996 and January 1997. The information is specific to the methodologies used for this particular study and may not comprehensively describe all capabilities of the PMDAM model.

PMDAM MODELING SYSTEM OVERVIEW

Introduction

The Power Market Decision Analysis Model (PMDAM) is a FORTRAN-based computer software model developed by Dr. Edward Cazalet in conjunction with the Bonneville Power Administration (BPA) to design and support competitve and regulated market analysis of power marketing resource acquisition transmission facilities, and power rate decisions. EDS/EMA acquired PMDAM to support strategic planning, competitive market modeling, multi-regional production costing and transmission economics modeling. The PMDAM model combines high-integrity planning software, up-to-date maintenance of data and power marketing information, the EDS commitment to on-going support, and fast response to client needs.

Figure 1 illustrates the basic structure of the PMDAM modeling system. All inputs into the center box determine equations which simulate physical utility operations as well as rules for decision making which determine when and how power contract and generating resource acquisition occurs. The bottom box shows the iterative solution algorithm that solves the system of equations. Based on the solution to these equations, PMDAM provides information on the operation and acquisition of the system elements and decision criteria outcomes. The double arrow lines in Figure 1 indicate this feedback.

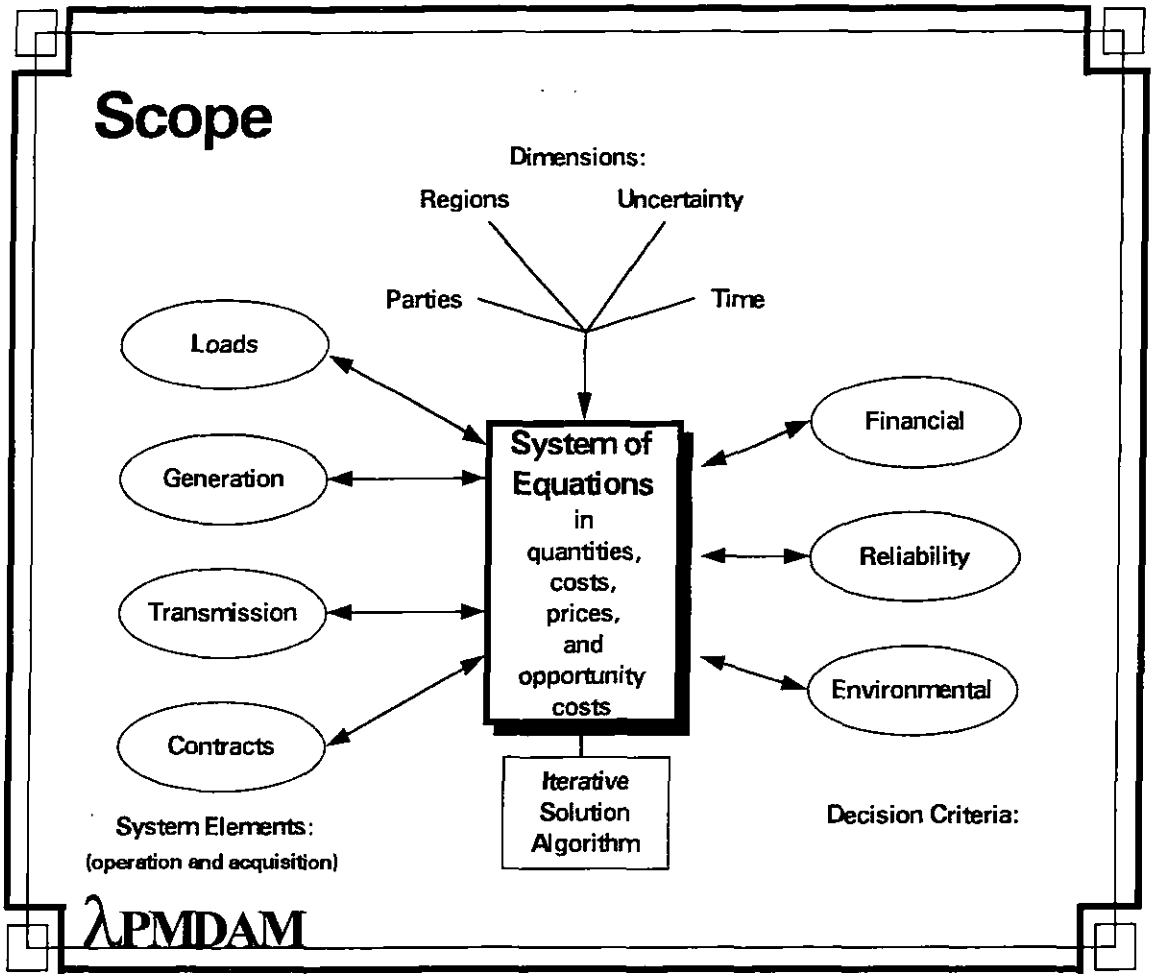


Figure 1 **Structure of the PMDAM Modeling System**

Capabilities

PMDAM models the operation and acquisition of generating and contract resources simultaneously through an iterative algorithm briefly described in the "Methodology" section below. In addition, PMDAM models ownership of all major inter-regional transmission lines including estimates of inter-regional losses. Scheduled transmission flows are based on the economic operation of generating resources and power contracts subject to contractual and transmission scheduling limits. For more information regarding the transmission modeling capabilities in PMDAM, see the section below titled "Transmission Modeling In PMDAM".

The PMDAM model represents all existing long-term power contracts between parties, as well as a large number of generic new contracts among all parties. This enables the model to decide on the amount of each type of contract to write among the parties. For more ir formation regarding the contract modeling capabilities in PMDAM, see the section below titlec "Contract Modeling In PMDAM".

Methodology

The following simple example illustrates the iterative algorithm applied by PMDAM to solve the large system of physical and behavioral equations and constraints. Every constraint/equation within the PMDAM system is associated with an opportunity cost (also referred to as marginal cost). A primary physical equation requires that, for a given hour and party operating in a particular region, total generation plus power purchases equal native load plus any sales.

The iterative algorithm starts with an initial system marginal cost estimate in mills/kWh at which the described equation is in balance. The model then dispatches al generating units and seeks all purchases (from other parties) which cost less than the estimatec marginal cost and serve only those sales loads worth more than the estimate. PMDAM then computes the actual surplus or deficient energy resulting from this estimate. Next, the model makes an adjustment to the estimate of the marginal cost by applying a step-size multiplier against the calculated energy surplus / deficiency. This process repeats until the surplus / deficiency converges toward zero. Figure 2 illustrates this simplified iterative algorithm.

The way the algorithm is constructed, the solution includes no additional energy from generation or purchases that would cost less than the converged marg nal cost and no additional sales opportunity worth more than the same marginal cost. Therefore the solution is a least-cost one.

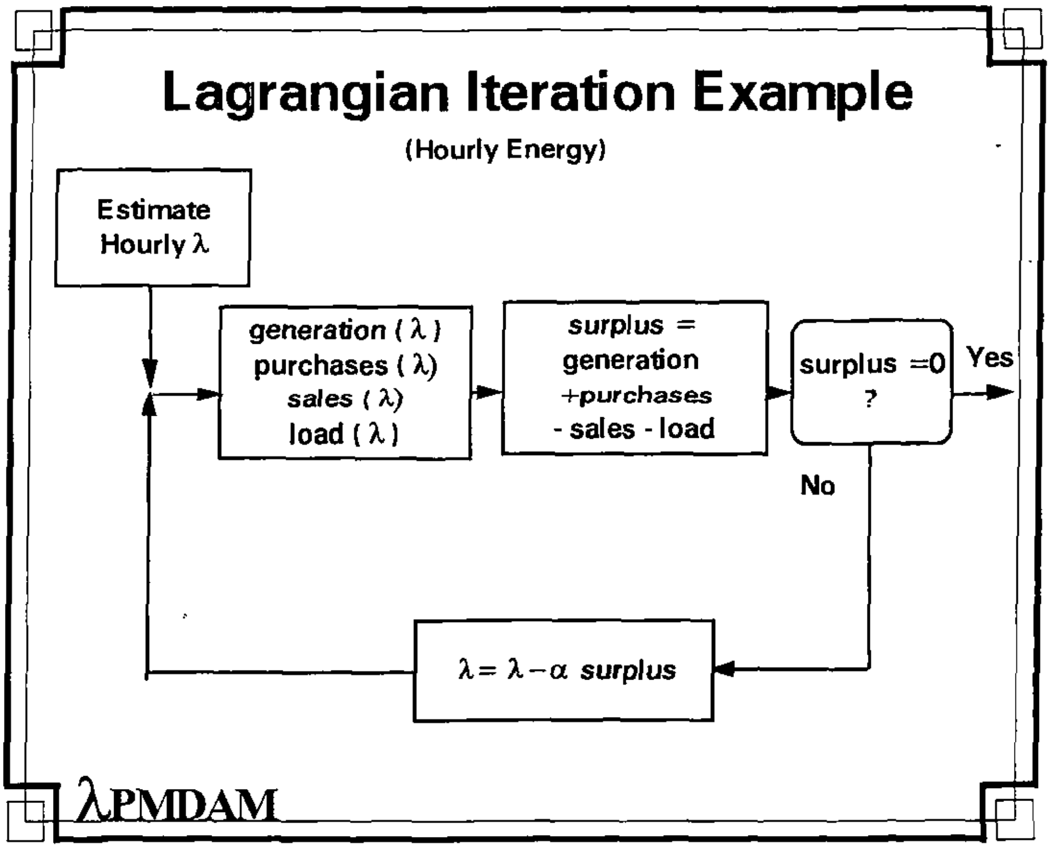


Figure 2 Lagrangian Iteration

Using this iterative methodology, the model calculates other opportunity or marginal costs associated with other equations and constraints such as non-firm energy, firm energy, and transmission and generation capacity costs. These opportunity costs show not only how much a party is willing to pay for each fundamental commodity in the market, but also the minimum price a party will accept for the sale of such commodities.

The power of this iterative algorithm is that the model automatically addresses the interconnection of a party's optimization problem (finding the least cost-of-service solution) to other parties' optimization problems. Simultaneous equation-solving capability allows PMDAM to correctly address the interdependence of some model variables. For example, the opportunity price of hydro energy is dependent on the operating cost of thermal energy generation. It is necessary to make decisions to generate hydro energy or increase storage capacity subject to maximum and minimum storage levels in conjunction with the commitment and dispatch of thermal units.

Decisions to invest in inter-regional transmission upgrades, acquire generating resources, and enter into power contract negotiations are highly interrelated and are best modeled in unison to capture the dynamics of the bulk power market. In multi-regional production costing and transmission modeling everything seems to be interconnected. The principal purpose of PMDAM is to cut through this complexity and develop insight into the key factors as well as key areas determining significant opportunities for increased efficiency and cost savings.

Contract Modeling in PMDAM

Firm Energy and Capacity Contracts:

Energy puts and calls can be modeled to meet the buyer's firm energy requirements without guaranteeing capacity. The decision maker on operation of the contracts can be either the buying party (call) or the selling party (put). PMDAM automatically operates the contract from the viewpoint of the decision maker who is seeking to minimize production costs. The energy delivered on such contracts can be limited by an annual load factor or represent take-or-pay type contracts where the buyer must take all energy specified by the contract.

New Generic Contracts:

The contract writing capability within the PMDAM modeling system will give you valuable insight into the bulk power market and as well as understanding of important buyer and seller market signals. Depending on inherent economic benefits for the potential buyer and seller of capacity, PMDAM writes non-firm and firm energy contracts between parties. Outputs from the PMDAM modeling system include quantities, prices, and duration of power contracts for the delivery of firm or non-firm energy and capacity.

Economy interchange transactions require almost no input, as PMDAM will automatically schedule hourly spot market transactions between the parties based on differentials in system marginal energy costs. In addition, economy energy flows are subject to physical constraints and limitations on transmission capabilities. The model will examine all contract combinations between parties defined in the database based on a pre specified maximum number of transmission owners over which the economy energy transaction is to occur. The user may control the amount of economy energy flows by specifying a minimum margin for such transactions expressed in mills/kWh. In addition, input variable margins for economy energy will determine how much additional economy energy to schedule per mill of benefit to the selling party. In this fashion, imperfect market conditions and behavioral decision making may be modeled.

PMDAM defines energy firmness as the ability of a utility to meet its firm load requirements under adverse hydro conditions and use of its committed resources year round. The model seeks out utilities which place different values on firmness of energy. For example, a one utility may place a high value on energy firmness due to the low flexibility in its hydro energy generation, whereas another may not value energy firmness as the utility has enough thermal resources installed to meet its annual energy requirements under adverse hydro conditions. The PMDAM modeling system automatically writes firm energy contracts between such parties where there is an economic benefit to both parties. Depending on the underlying loadshapes of the two parties and which party is decision maker in scheduling of the contract, PMDAM calculates the appropriate load factors, contract size, and prices for such transactions.

Demand contracts writing takes place between parties which have different needs for capacity. Based on respective reserve margin or loss of load probability criteria, installed capacity, and peak load hours, two parties may be on opposite ends of the spectrum with respect to how they view the value of capacity. One may have a surplus, the other a shortage. PMDAM recognizes such differences on a monthly basis and suggests monthly amounts of contract capacity between parties. The decision for two parties in the model to enter into a long-term or short-term capacity contract is dependent on the value of capacity over time. One party may be limited to building more costly generating resources and may want to enter into a long-term capacity contract to defer installation of expensive generation. Another utility may be part of a subregion in which its neighboring utilities have an abundance of capacity and opt for a shorter-term capacity contract with substantial savings over long-term contract rates.

Acquisition of Resources

The decision for a utility to acquire new generating resources is directly linked to the decision to acquire demand and capacity contracts. PMDAM currently has extensive capacity expansion capability both for firm contracts and generating facilities. PMDAM, by design, determines the least-cost amount and mix of generating capacity additions and firm power contracts among companies. The capacity expansion plans generated by PMDAM reflect transmission constraints, access, ownership, and losses. The plans are integrated with the modeling of system operation and account for the individual reliability, discount rate, environmental, load, and cost factors each utility faces.

In a competitive marketplace, the value of capacity is not dependent on the embedded cost of the resource but on supply and demand. Depending on the availability of capacity in the subregions modeled, a party short on capacity may be well advised to seek a long-term power contract in favor of building a new resource. PMDAM performs this type of cost-benefit analysis. Figure 3 shows the components of the net benefits associated with contract and resource acquisition decision making. Based on the comparison of the sum of these net benefits on a present- value basis, PMDAM will form the buy-versus-build decision.

Operation Benefits

- Thermal resource benefits = hourly system λ
  - variable operating costs
  - variable fuel costs
- Economy contract benefits = buyer hourly system λ
  - seller hourly system λ
  @point of delivery with transmission loss and transmission λ adjustments
- Storage discharge benefits = hourly system λ
  - storage energy λ
- Storage recharge benefits = storage energy λ
  - hourly system λ / efficiency
- Hydro resource benefits = hourly system λ
  - hydro energy opportunity cost

λPMDAM

Figure 3 Operation Benefits

Mothball Analysis

In an increasingly competitive environment, utilities will closely examine the decision to mothball existing power plants if the fixed O&M savings resulting from mothballing outweigh any operational and reliability value of the units. PMDAM will allow the user to enter mothball costs by unit and will make to decision to mothball if the savings outweigh the net benefits. As load growth occurs over time and the value of capacity increases, PMDAM will take the unit out of mothball status and return it to operation if the underlying economics warrant such action.

Transmission Modeling in PMDAM

The PMDAM transmission model is data driven. It is possible to represent any number of lines, busses areas, and points of delivery in the model. In the PMDAM model each line in the network can be the property of one or more model parties or companies. The ownership of a line can change at intermediate points of delivery on the line. Limits are provided on each line by ownership and on the simultaneous transfer among groups of lines. Limits can depend on other variables so it is possible to model nomograms and area requirements.

Hourly Transmission Operation

The PMDAM model solves a system of equations for each hour representing both the physics and the economics of the transmission system. This system of equations is fully integrated with the systems of equations used by the model for production costing, acquisition, and all other model computations. PMDAM uses no sequential approximations on the solution of these equations, in contrast to other models that use a less accurate step-by-step procedural approach. The model carries out these computations in chronological order hour by hour.

The PMDAM model can represent hourly transmission system operation using a pipeline/transportation model. In the pipeline/transportation model, scheduled and actual flows are identical and losses are proportional to the square of the flow or load on a line. In this transportation mode, PMDAM will dispatch generating projects to provide the least-cost mix of generation, purchases, and sales for each company, assuming only mutually beneficial interchange among companies. Interchange sales on the transmission network are limited by ownership shares of lines along access paths determined by the model users. It is also possible to simulate open access. All of the interchange transactions recognize losses as a function of line loading and these losses affect the economics of the transactions. The model computes prices on transmission lines as a part of the algorithm. These prices may be cost of service or market based.

Transmission Firm Planning

PMDAM also uses the firm capability of each line, or group of lines, to limit and allocate the use of the transmission system for firm contracts. All existing firm contracts among parties are input to PMDAM. PMDAM adds new firm power contracts as part of the generation and power contact acquisition process in the model. The total requirement for firm transmission capacity specified in these contracts is compared to the available firm transmission capacity. Determination of access to firm transmission capacity is through model input data.

The PMDAM algorithm simultaneously solves for the least-cost additions of generation projects and power contracts in each month and year of the model horizon, the firm capacity opportunity cost in $/kW-mo for each party and area, and the firm transmission capacity opportunity cost for each line. This transmission opportunity cost is related to the differences in capacity opportunity costs among the model areas.

The firm transmission opportunity cost in each direction plus the hourly transmission opportunity costs provide valuable information to transmission planners on the need and value of new lines or upgrades to eliminate bottlenecks.

PMDAM can also summarize the firm and hourly transmission opportunity costs as a present value over the assumed life of a transmission line. This present value can be compared to the present value of capital and operating costs of a project to add transmission capability. In contrast to other models, with PMDAM it does not take multiple runs to determine the opportunity cost of transmission capacity. A single run will provide operating and firm transmission opportunity costs for all lines in the model.

A potential and very feasible enhancement of PMDAM would be to provide information on the costs of new lines and upgrades and let PMDAM simulate the acquisition of these lines in the same way it simulates the acquisition of generating resources and power contracts.

PECO STATEMENT NO. 8

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY

FOR ISSUANCE OF A QUALIFIED RATE ORDER

UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY

OF

BANGALORE S. VENKATESHWARA

Regarding Market Prices for PECO Energy Generation

CONTENTS

DIRECT TESTIMONY OF B. VENKATESHWARA

I. QUALIFICATIONS

Q. **Please state your name, position, and business address.**

A. My name is Bangalore S. Venkateshwara. I am a Vice President at ICF Resources Incorporated. My address is 9300 Lee Highway, Fairfax, Virginia, 22031. ICF Resources has been at the forefront of consulting on energy issues for over 20 years. The firm provides consulting services related to all sectors of the U.S. energy economy, including oil, natural gas, coal, electric utilities, and independent power.

Q. **Please describe your educational and professional background as well as your responsibilities at ICF Resources.**

A. Appendix A to this testimony contains a copy of my resume which provides the requested information.

Q. **Please describe your responsibilities and work at ICF Resources**

A. I direct analytic projects in the energy area for a wide range of clients, both in the public and private sectors and have offered expert testimony in several jurisdictions. I have also been responsible for directing a large number of studies dealing with projections of electric prices in several U.S. bulk power markets including, for instance, PJM, the New York Power Pool, (NYPP), the New England Power Pool (NEPOOL), Virginia and the Carolinas (VACAR), Peninsular Florida, and the Midwest. These studies have been based on integrated, market-wide modeling designed to reflect the workings of a deregulated bulk power market. In particular, many of these studies have focused on PJM.

II. INTRODUCTION AND SUMMARY

Q. **On whose behalf are you testifying?**

A. I am testifying on behalf of PECO Company ("PECO"), 2301 Market Street, Philadelphia, PA 19103.

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

A. As part of its application for a Qualified Rate Order to recover a portion of its stranded costs, PECO has prepared estimates of its stranded costs. One element of such an estimate of stranded costs is the market price for electric capacity and energy that is expected to prevail in the future PJM bulk power market. A related calculation is the electric capacity and electric energy revenues that each specific PECO unit would expect to realize if it sold its output into the PJM bulk power market. The revenues that a specific unit would realize will depend upon its operating characteristics (e.g., a higher variable cost unit would operate for fewer hours than a lower variable cost unit, affecting the respective electric energy revenues of each). As further discussed by Mr. Hill, the electric capacity and electric energy revenues on a unit-by-unit basis are used, in part, to derive a present value income estimate for generation units.

In the above context, the purpose of this testimony is to provide the following:

1. Estimates of the electric capacity and electric energy revenues that each PECO unit is expected to derive by selling its electric capacity and energy into the future PJM bulk power market.
2. Estimates of the underlying fuel and related costs that each PECO unit is expected to see, assuming that it faces the same market for fuels and SO_2 allowances as other, competing bulk power generators.

Q. **Please summarize the results of your work.**

A. The results of my work are summarized in Exhibit BSV-1.

III. APPROACH

Q. **You have mentioned that your estimates pertain to the "future PJM bulk power market." Please explain what you mean by this phrase.**

A. At the present time, PJM functions as if it were one system to achieve the highest practicable degree of economy and reliability. The current PJM system is governed by the PJM Interconnection Agreement, which is an agreement entered into by the various regulated, franchised utilities in PJM.

PJM, like other markets, is in the process of reforming its institutional arrangements so as to facilitate an open and competitive bulk power market, consistent with the Federal Energy Regulatory Commission's (FERC) Order 888. Although there currently are competing proposals to reform PJM, I believe that certain basic premises can be assumed to prevail in the future. They are:

1. The responsibility for operation and real-time coordination of the bulk power system across the single control area, PJM, will be in the hands of an Independent System Operator (ISO). The ISO will (i) administer one PJM-wide transmission tariff aimed at *facilitating an open and competitive bulk power market, and (ii) setting "rules of the road"*, as necessary, to maintain reliability.
2. Owners of generation ("generators" or "generation companies") within PJM will be able to sell their output to "Load-Serving Entities" (LSEs) -- or those who serve electric customers at retail -- by delivering such output anywhere on the PJM bulk power transmission system. This sale of output will be facilitated by the fact that LSEs will be eligible for Network Transmission Service or service that will enable them to take receipt of electric output anywhere on the bulk power transmission system.
3. Generation companies outside PJM will be able to deliver their output on the PJM bulk power transmission system pursuant to the applicable transmission tariff administered by the ISO. Similarly, generation companies within PJM will be able to sell their output to buyers outside PJM and will have the ability to deliver their output to interconnection points between PJM and neighboring regions pursuant to applicable ISO-administered transmission tariffs. Service into PJM, outside PJM, or through PJM will be subject to the availability of adequate transmission capacity.

4. In this context, there will be an active hourly market for electric energy in which the price of electric energy will be determined by the interaction of hourly supply and demand. The hourly market price for electric energy (i.e., spot energy) will be visible to buyers in after-the-fact hourly prices declared by an exchange and in indices that track market information on the transactions entered into by willing buyers and willing sellers.
5. Buyers and sellers will also enter into agreements for (a) "pure capacity" (as discussed below), as well as (b) capacity and associated energy, on both a short and long-term basis.
6. It is conceivable, although not certain, that in the future there may exist an hourly market that reflects the price of both capacity and energy.

My analysis is based upon the premise that a number of generators (i.e., sellers inside and outside PJM) and LSEs (i.e., buyers inside and outside PJM) will participate in what will be a competitive bulk power market and that the price of electric capacity and energy will be determined by the resulting dynamics of supply and demand.

Q. **Assuming that the future bulk power market will possess the above characteristics, please provide the conceptual underpinnings for your market price of capacity and energy.**

A. The market price of electric capacity and energy (or the market price of electric output) in the bulk power market of the future can be thought of as having two components:

1. The price of electric capacity refers to a payment (typically stated in \$/kW/month or \$/kW/year) that a buyer makes to a seller in exchange for which payment the buyer obtains the right to call on the seller's electric energy at a known price for electric energy. The buyer makes the payment in \$/kW/month or \$/kW/year regardless of whether or not it calls upon electric energy. The price for electric energy is paid only if the buyer calls upon such energy. I use the term "pure capacity" to refer to a situation in which the price of electric energy attaching to the capacity is set at a relatively high level, so that the buyer does not call upon the energy often. A classic example would be one in which the price of electric energy is set equal to say, the variable cost of producing electric energy using an aging combustion turbine. A buyer that has paid for and purchased such a right has effectively protected itself against a curtailment or a sharp run-up in the price of electric energy during hours when the balance between supply and demand is tight.
2. The price of electric energy can be viewed as the price during an upcoming hour at which a single buyer can buy a reasonable increment and a single seller can sell a reasonable

increment of electric energy in MWh/hr, provided that either buyer or seller can terminate the transaction with one-half hour's notice. Under this definition, during all hours, except those hours when load might exceed available resources in the marketplace, the marginal generation will determine the price of electric energy. During hours when loads exceed available resources, the price effectively will be set by the "willingness to pay to avoid being curtailed" on the part of buyers.

Q. **What methodology do you employ to project the market price of pure electric capacity?**

A. With respect to the price of "pure capacity", it will be equal to the properly annualized market-based price of a new combustion turbine, as of the date when the market will need to add capacity to maintain adequate reliability. This is because a combustion turbine represents the most attractive source for providing "pure capacity" and hence the market price for "pure capacity" will be determined by a combustion turbine. Prior to the date when additional capacity is needed to maintain adequate reliability, the market is in "excess capacity". During such period of excess capacity, the price of capacity will be greater than zero, but less than the properly annualized market-based price of a new combustion turbine. The approach I employ is to infer the price of pure capacity during periods of excess capacity by examining (i) the degree of excess capacity, measured by the extent to which the prevailing reserve margin exceeds the level required to maintain adequate reliability; and (ii) actual transactions for "pure capacity" entered into by willing buyers and willing sellers, during periods of excess capacity.

Q. **What methodology do you employ to project the market price of electric energy?**

A. To project the market price of electric energy, I employ a multi-area production cost modeling framework that mimics the behavior of the future bulk power market. In particular, the production cost model, the Integrated Planning Model (IPM), reflects the following:

1. A representation of PJM that (a) delineates East, West and South PJM with realistic transmission constraints across these regions; and (b) reflects appropriately constrained transmission links between PJM and other bulk power markets, notably the New York Power Pool (NYPP) and the East Central Area Reliability Council (ECAR). In my model-based projections, all the loads and generating resources in NYPP and the New England

Power Pool (NEPOOL) are represented, while the imports from ECAR into PJM are modeled as an external transaction.

2. A representation of loads and generating resources across the PJM bulk power market. In particular, as part of representing this balance into the future, loads are projected into the future and future generating resources that the market can be rationally expected to bring on line are incorporated. Similarly, the availability and operating characteristics of existing units are represented. As noted, it is this balance between supply and demand that determines the spot electric energy price.

3. Future fuel prices faced by the bulk power market which, absent unit-specific circumstances, will be the same for PECO and all other generators are based on explicit projections.

4. Acid rain compliance decisions are represented and their effect on the spot electric energy price is taken into account. No comparable adjustment is made for NO_x or particulate emissions.

A more detailed explanation of the working of IPM can be found in Appendix B. The IPM results can be used to derive a spot electric energy price that matches the definition set forth above. In particular, IPM generates a spot electric energy price for each model segment in each season. These results can be interpreted by a sequence of additional calculations to yield hourly spot electric energy prices.

Q. **Please explain whether the results from IPM capture differences in spot electric energy prices across the model regions and the significance of these results in the context of the estimates presented here.**

A. The results from IPM do capture differences in spot electric prices across the model regions (i.e., East, West, and South). Notably, during transmission-constrained periods, the spot price in a transmission constrained receiving region such as East PJM will be higher than the spot price in an exporting region such as West PJM. For purposes of estimating the revenue realized by each PECO unit, I use the spot price corresponding to the region in which the unit is located. Because a large number of PECO units are located in East PJM and spot electric energy prices in East PJM are in general higher than West PJM, the resulting realized revenue for PECO units will be higher than what might have been realized with unconstrained spot prices. This, in turn, means that from the perspective of estimating stranded costs, the approach of using area-specific spot prices is conservative (i.e., acts to lower stranded cost estimates).

Q. **Are you aware that there are alternatives to area-specific pricing that have been proposed in PJM restructuring proposals?**

A. Yes, I am aware that in PJM restructuring proceedings, one option that has been proposed has been the use of locational marginal prices which, in practice, may end up being close to having a small number of distinct areas across which prices differ substantially during some periods. PECO, on the other hand, has proposed the use of spot prices that are calculated "after-the-fact" under an assumption of no transmission constraints. The costs associated with relieving transmission constraints and payments for such costs are then handled separately outside of the declared spot prices under the PECO proposal. Because the use of area-specific spot prices from IPM is, as noted, conservative in the context of this work, it is appropriate to use that approach here, without attempting to address the technical merits (or lack thereof) of the competing proposals.

IV. RESULTS

Q. **In addition to the basic premises listed above with respect to the future bulk power market, are your results based upon specific projections about the fuel market and economic conditions?**

A. Yes, they are based upon a set of explicit projections.

Q. **Please state the key projections underlying your results.**

A. The key projections relate to (a) overall electric market conditions, including electric load growth, the response of the marketplace to such load growth, and the performance of existing and future generating units (notably their availability); and (b) future market conditions in the gas, oil and coal markets.

Exhibit BSV-2 sets forth the key projections underlying my results. These projections fall within a reasonable range.

Q. **How far in time do your model-based projections extend?**

A. My model-based projections extend through 2015. Given the inherent uncertainty, especially after 2015, in the underlying drivers, I felt it appropriate to terminate the model-based projections as of 2015.

Q. Are there any points you would like to emphasize with respect to your projections?

A. Yes I would. In particular, with respect to the driving projections, there are three items I would like to emphasize.

1. I have used the official projection of the Mid Atlantic Area Council (MAAC) utilities as embodied in their annual filing known as the EIA-411 in order to maintain consistency with the official projections of the individual PJM utilities.
2. My fuel prices reflect the most recent projections independently developed by ICF Resources in its Energy Service.
3. My projection is that, over the long-term, poolwide planning reserve margins in PJM will settle around 18 percent. For the 1998-99 planning year it has fallen to 20 percent. The expectation of a further decline to 18 percent is reasonable, given certain trends that are in place today. Notably, with a deregulated market, there will be a greater incentive to improve unit availabilities and this, in turn, will lower the required reserve margin, all else being the same.

Q. Please describe the results of your analysis.

A. The results of my analyses are set forth in Exhibit BSV-1. Exhibit BSV-1 shows the realized market price of PECO units, taking into account both the market price for capacity and energy. In particular, the realized market price reflects (a) the capacity value as the product of the market price for capacity in $/kW/year and the available capacity of the PECO unit; and (b) the energy value as the product of the electric output supplied by the PECO units during their hours of operation and the market price for electric energy during those hours of operation. For convenience the total value realized in dollars is divided by the electric output in MWh and the resulting number is expressed in $/MWh.

Q. **Do the realized values shown in Exhibit BSV-1 reflect the prospect of ending the analysis for certain PECO units that reach a point when they do not generate a positive net contribution?**

A. No, they do not. Within the time horizon of the projections, I have assumed that no PECO units reach the point where they do not generate a positive net contribution (the "end-of-analysis point"). However, I understand that in making its stranded cost estimate, PECO applies an end-of-analysis point for those units at which the "to-go" costs exceed realized market value. From an economic perspective, such an adjustment is entirely appropriate. Because PECO makes this adjustment, the estimated realized market value in Exhibit BSV-1 for some years may not match perfectly with a comparable PECO exhibit. In fact, if those units that reach the end-of-analysis point actually cease to generate electric energy, their small magnitude, relative to the size of the PJM market, will not, in and of itself, have a material impact on my market price projections.

Q. **Do you have any other observations to make with respect to these results?**

A. It is worth noting that while my projections allow for interactions with other regions, subject to transmission constraints, in determining electric energy prices, they do not reflect the ability of buyers in PJM to buy pure capacity from neighboring markets. My rationale for this somewhat conservative assumption is that the planning reserve margins established for the PJM market in my modeling already reflect the ability of the market, as a whole, to rely on capacity from other regions, (subject to available transmission) to prevent a loss of load. However, subject to a specific examination of the transmission situation, it is conceivable that a buyer could arrange to purchase pure capacity from a neighboring region to meet PJM capacity obligation. Assuming that some level of available capacity from outside PJM could participate in the PJM capacity market will mean downward pressure on PJM capacity prices.

Q. **Does that conclude your direct testimony?**

A. Yes, it does.

Summary of Results

Year	**Realized Market Price for All PECO Units[1,2]** Nominal$/MWh[3]	**Associated Fuel Cost for All PECO Units[2]** Nominal $/MWh[3]
1999	27.71	7.60
2000	30.31	8.15
2001	32.89	8.26
2002	37.31	8.46
2003	38.44	8.63
2004	39.90	8.86
2005	41.68	9.10
2006	43.80	9.44
2007	45.58	9.77
2008	47.72	10.16
2009	49.69	10.51
2010	52.01	10.94
2011	53.81	11.26
2012	55.95	11.64
2013	58.13	12.11
2014	60.33	12.59
2015	62.66	12.96

[1] These projections represent the market price realized by all PECO units for sales into the PJM bulk power market:

$$\frac{\text{Total Revenues for Capacity and Energy Realized by all PECO Units}}{\text{Total MWh Generated by all PECO Units}}$$

[2] These projections do not consider the prospect of ending the analysis for certain PECO units that reach a point when they do not generate a positive net contribution. In fact, if those units that reach the end-of-analysis point actually cease to generate electric energy, their small magnitude, relative to the size of the PJM market, will not, in and of itself, have a material impact on my market price projections.

[3] Stated in nominal dollars applying GDP deflator projections supplied by PECO

Overview of Key Driving Projections

Parameter	Forecast
Net Internal Demand	Actual Year / Demand (MW) 1994 / 46,019 1995 / 48,577 Projected Year / Demand (MW) 2000 / 47,667 2005 / 50,298 2010 / 53,074 2015 / 56,001
Net Energy for Load	Actual Year / Energy (GWh) 1994 / 238,379 1995 / 243,043 Projected Year / Energy (GWh) 2000 / 257,992 2005 / 276,054 2010 / 295,387 2015 / 316,074
Poolwide Planning Reserve Margin	18%
Response to Load Growth	Near term load growth does not necessitate additional capacity until 2002. Medium-term load growth is met primarily with new gas-fired combined-cycle units, with long-term capacity additions consisting of a mix of gas-fired combined cycle units and gas-fired combustion turbines.
Generating Unit Non-Fuel Variable O&M Costs (Nominal $ per MWh)	Year / Range 2000 / 1.1 - 2.2 2005 / 1.3 - 2.5 2010 / 1.5 - 3.0 2015 / 1.8 - 3.6
Seasonal Henry Hub Gas Prices (Nominal $ per million Btu)	Season Year / Summer / Winter / Shoulder 2000 / 1.97 / 2.26 / 2.08 2005 / 2.50 / 2.83 / 2.63 2010 / 3.25 / 3.66 / 3.40 2015 / 4.04 / 4.53 / 4.22
Seasonal Gas Transportation (Nominal $ per million Btu)	Season Year / Summer / Winter / Shoulder 2000 / 0.35 / 0.69 / 0.49 2005 / 0.41 / 0.80 / 0.57 2010 / 0.49 / 0.96 / 0.68 2015 / 0.58 / 1.14 / 0.81

Parameter	Forecast
Examples of Delivered Oil Prices (Nominal $ per million Btu)	0.5%S Resid / Distillate 2000 3.66 4.45 2005 4.45 5.37 2010 5.56 6.67 2015 6.91 8.24
Example of Mine Mouth Coal Prices for coal used at Cromby 1 (Central Pennsylvania) (Nominal $ per ton)	Central Penn. (1.5-2% Sulfur) 2000 23.1 2005 22.9 2010 25.8 2015 29.0
Examples of Delivered Coal Prices (Nominal $ per million Btu)	Cromby 1 / Keystone 1&2 2000 1.52 1.03 2005 1.57 1.06 2010 1.73 1.19 2015 1.97 1.33
Coal Plant Availability	Average coal unit availability of 82.4%
Acid Rain Legislation	Units assumed to scrub are: Cromby 1, England 2, Eddystone 1-2, and Conemaugh 1-2.
Nuclear Performance	Annual Capacity Factor 75%
Power Purchases by individual utilities and the PJM Pool	Explicit consideration given to power purchase agreements that affect the energy market: PEPCO and OES/APS (450 MW), and economy energy available from the ECAR region. Links to the NYPP, as well as representation of NYPP and NEPOOL loads and generating resources provide for electricity transactions between PJM and NYPP.
Independent Power Producer Representation	Year 2000 On-Line Capacity: 4,655 MW

APPENDIX A
Resume

B. VENKATESHWARA

EDUCATION

1983	Ph.D, Energy Management and Policy, University of Pennsylvania
1980	M.B.A. Finance/Quantitative Methods, Wharton School, University of Pennsylvania
1977	M.S. Mechanical Engineering, Clemson University
1976	B. Tech, Mechanical Engineering, Indian Institute of Technology

EXPERIENCE

Dr. Venkateshwara is a Vice President at ICF Resources Incorporated and directs work dealing with electric markets. He has directed analytic projects in the energy area for a wide range of clients both in the private and public sectors. Dr. Venkateshwara has offered expert testimony in a number of matters in several jurisdictions.

In a recent Massachusetts proceeding on electric industry restructuring, he offered testimony and prepared a report on the use of auction processes to estimate generation-related stranded costs. In a Pennsylvania proceeding dealing with the complaints of three cogenerators, Dr. Venkateshwara offered expert testimony on avoided cost and capacity need issues. He also provided a sworn affidavit on the matter of estimated payments in excess of avoided cost in a Federal Energy Regulatory Commission (FERC) proceeding. Other matters on which Dr. Venkateshwara has led analytic efforts include: assessment of market power in the relevant product and geographic markets for electric power; analyses of electricity and coal transportation markets from an anti-trust perspective; and an evaluation of natural gas purchase contracts in a FERC proceeding dealing with the affiliated entities test under the Natural Gas Policy Act (NGPA).

Dr. Venkateshwara has served as a principal in multi-disciplinary teams and dealt with the evaluation and negotiation of several dimensions of project-specific transactions: economic analyses; project financing factors; and regulatory considerations. Also, Dr. Venkateshwara has directed the analyses of several studies dealing with the economic aspects (e.g., dispatch, transmission, power sales revenue projections, and avoided cost projections) of specific QF/IPP transactions. In addition, Dr. Venkateshwara has also managed dozens of analytic studies covering such areas as the impact of deregulation on various players in the electric industry, the impact of low oil and gas prices on U.S. electric generation, integrated (supply and demand) modeling of utility systems and power pools, natural gas industry contract problems and possible solutions, and interfuel competition in industrial end-use markets.

Analyses to Support Specific Transactions and Regulatory Proceedings

- Support for Regulatory/Legal Proceedings: Dr. Venkateshwara has served as the principal analyst in several regulatory/legal proceedings in which ICF has provided research and analytic assistance. In particular, his experience includes:

    - Expert testimony in a recent Massachusetts proceeding dealing with electric industry restructuring on the matter of using an auction process to estimate stranded costs. In particular, the characteristics of alternative auction approaches, including the ascending bid auction used to auction radio spectrum licenses, were assessed.

    - Prepared a report to support a Federal Energy Regulatory Commission (FERC) filing seeking blanket authorization to engage in wholesale electric sales. The report assessed the market power (or lack thereof) of an electric utility in the relevant geographic and product markets for generation..

    - Sworn affidavit on behalf of a New York utility estimating payments to a Qualifying Facility (QF) in excess of avoided cost..

    - Expert testimony in a proceeding before the Pennsylvania Public Utility Commission on the issues of capacity need and avoided cost. Issues addressed by Dr. Venkateshwara include: utility load projections; avoided cost standards pursuant to the Pennsylvania PURPA regulations; and ratepayer impacts.

    - Analytic direction for an ICF study, performed for the Federal Energy Regulatory Commission (FERC), dealing with the environmental impacts of the FERC's Notice of Proposed Rulemaking (NOPR) on independent power producers and bidding programs, including consideration of "wheeling-in/wheeling-out" proposals.

    - Preparation of research and analytic materials addressing anti-trust issues in coal transportation markets

    - Assistance to lead counsel in a Federal Energy Regulatory Commission (FERC) proceeding concerning pipeline gas purchases from an affiliate.

- Assistance in the Negotiation of Specific Transactions: The implementation of energy projects generally requires a balancing of the multiple and sometimes conflicting aims of different parties within the constraints imposed by market, technical, and regulatory factors. At the request of clients, Dr. Venkateshwara has served as a principal on teams responsible for negotiating project-specific agreements. For example, he served as a principal on a team that negotiated on behalf of a state agency in the Northeast in connection with the cost and payment terms for a 115 kV underwater transmission line. These negotiations covered all aspects of the transaction: negotiating strategy, economics, regulatory factors, and technical constraints. For other clients, Dr. Venkateshwara has been a direct contributor to power sales contract negotiations. The negotiations have included interconnection and transmission considerations.

- Analytic Support for Specific Transactions: Dr. Venkateshwara has provided financial institutions and energy project developers with an independent evaluation of complex contractual provisions and market conditions. Examples include: an independent assessment of the expected hours of operation of several large (total value in excess of $1 billion) dispatchable cogeneration projects in PJM; forecasts of electric revenues that could be expected under market-based pricing provisions in power sales contracts (e.g., revenues tied to the PJM billing rate; revenues based on tariff-based contracts in New Jersey); and the risk-return tradeoff inherent in "front-loading" of power sales contracts. In certain cases, Dr. Venkateshwara has focused on transmission possibilities in inter-regional power markets (e.g., Southern Company to Florida).

Energy Market Analyses

- Integrated Modeling of Electric Utility Systems/Power Pools: Dr. Venkateshwara has managed and provided analytic leadership for various ICF consulting assignments dealing with integrated (i.e., the load and the supply side) modeling of individual utility systems or power pools. The systems examined include Penn-Jersey-Maryland (PJM), New York Power Pool (NYPP), and New England Power Pool (NEPOOL). These analyses focused on dispatch and avoided cost calculations.

- Industry Analyses: Dr. Venkateshwara has considerable experience in directing industry-wide studies that provide clients with an understanding of the fundamental factors affecting an industry and the opportunities and challenges that result. For example, Dr. Venkateshwara was the lead analyst on a major Gas Research Institute study of the potential for industrial cogeneration. In the natural gas area, he assessed for a major financial institution the magnitude of the take-or-pay problem in the U.S. gas industry and the prospects for resolution. Other industry studies directed by Dr. Venkateshwara include: impact of wellhead gas deregulation on the domestic pipeline industry, and the implication of lower oil and gas prices for the electric generation market and the coal industry.

- Market Studies: Shifts in fundamental economic factors or in the regulatory/legal environment can translate into opportunities or threats in specific markets. Dr. Venkateshwara has assisted numerous clients understand both qualitatively and quantitatively the scope and nature of such opportunities and threats. Market studies in which Dr. Venkateshwara was a principal include: studies of the impact of avoided cost prescriptions or contractual pricing provisions on the power sales revenue and associated risk for non-utility power producers; the possible use of electric market indicators such as PJM billing rate differentials to estimate the opportunity cost of transmission; studies of the impact of inter-regional competition and interstate pipeline tariffs on wellhead gas pricing in a single producing region; analyses of the possible options open to a utility to create competition for coal transportation services in a specific origin-destination markets; and competitive analyses of alternative industrial technologies and the implications for natural gas and electricity use.

- Financial Studies: Dr. Venkateshwara has supervised the evaluation of alternative financing options for energy projects, including consideration of tax and regulatory factors. In the cogeneration/independent power area, these evaluations have dealt with such options as limited partnership arrangements, leveraged leasing, and sale-leaseback options. In a recent project, Dr. Venkateshwara assisted a financial institution examine alternative ways of dealing with a bankrupt resource recovery facility to which substantial amounts of capital had been loaned. The work included a review of alternative power sales opportunities including the prospects for wheeling power.

PROFESSIONAL AFFILIATIONS

The Cogeneration Institute
Association of Energy Engineers
International Association of Energy Economists

SELECTED PUBLICATIONS AND PRESENTATIONS

"Power Pricing Strategies for the Generation Company," Invited Speech to the Infocast Conference on *Becoming a Profitable Genco in a Competitive Market,* November 14, 1996.

"Creating Value in the Delivery of Energy and Capacity and Some Predictions of Future Price Trends," Invited Speech to the Infocast Conference on *Strategic Issues for Power Marketers,* May 2, 1996.

"Considering in Emerging Renewable/Industrial Project Financing Opportunities," Invited Speech to McGraw Hill Conference on the *Market for Project Financing,* New York, May 6, 1992.

"Special Considerations for Financing Transmission Facilities: How One Transmission Line Was Financed," Invited Speech to Infocast Conference on *Power Transmission: Access, Pricing, & Regulation,* Washington, D. C., April 22-23, 1991.

"The Essence of Feasibility Studies," Invited Speech to Infocast Conference on *Project Finance,* Los Angeles, April 30, 1990.

"Sorting Out the Good Deals from the Marginal Ones in Independent Power Projects", Presented to the 12th World Energy Engineering Congress, October 26, 1989.

"Marketing Gas to Future Electricity Producers: More than Writing Purchase Orders" (co-authored with Daniel Klein), published in *Natural Gas,* July 1988.

"Risks to Partnerships in Cogeneration Ventures." Presented to the Second International Modeling and Computer Simulation Symposium on Energy Modeling and Simulation, August 1984.

"Investment Decisions Under Certainty: A Behavioral Hypothesis." Presented to the *Joint National Meeting of the Institute of Management Sciences and the* Operations Research Society of America, April 1983.

SELECTED ICF REPORTS

"Assessment of IPL's Position in the Relevant Geographic and Product Markets for Electric Generation", Prepared for American Energy Service Corporation (an affiliate of Indianapolis Power & Light), September 1996.

"Design of Auction Process to Mitigate and Estimate Stranded Costs of COM/Elec's Generation Entitlements," Prepared for COM/Electric and submitted to the Massachusetts Department of Public Utilities in D.P.U 96-100, June 1996.

"Incremental Cost Pricing of Transmission Services", Prepared under contract with U.S. Department of Energy, December 1994.

Several confidential reports dealing with dispatch and power sales prices applicable to specific QF projects. 1989-1996.

"Review and Analysis of PJM Billing Rate Forecasts", Confidential Report for a Private Client, May 1989.

"Low Oil Prices and U.S. Coal Demand," Prepared for the U.S. Department of Energy, May 1987.

"The Take-or-Pay Problem in the Interstate Gas Transmission Industry", Confidential Report for a Private Client, August 1986.

EMPLOYMENT HISTORY

ICF Resources Incorporated	Vice President	1986-Present
Energy and Environmental Analysis, Inc.	Senior Consultant	1983-1986
Synergic Resources Corporation	Analyst	1982-1983

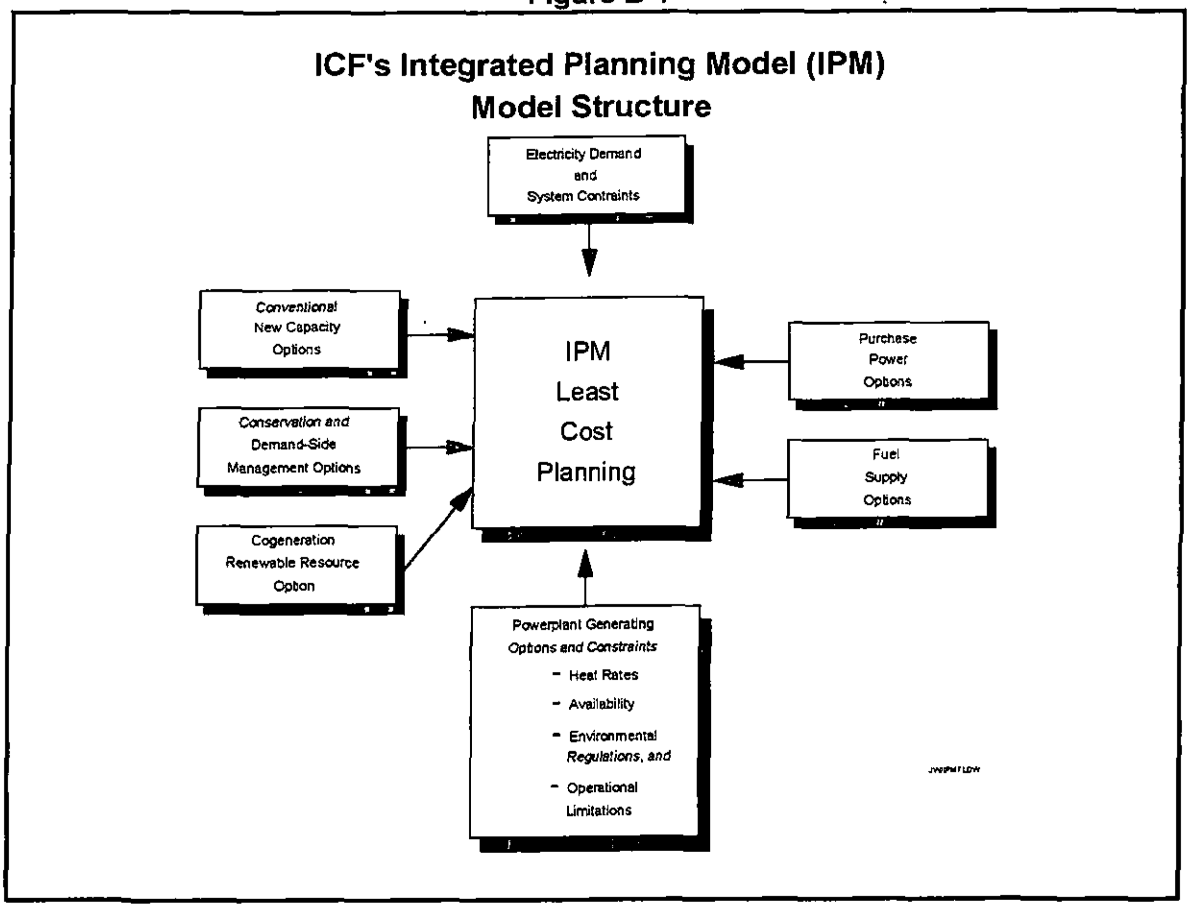
APPENDIX B
ICF Resources' Integrated Planning Model

ICF RESOURCES' INTEGRATED PLANNING MODEL ("IPM©")

ICF Resources' IPM© is the principal analytic tool used in this study. IPM© is a linear programming model which finds an optimal dispatch pattern and choice of resource options to meet electricity demand at the minimum cost. The model can be used to study several behavioral factors, such as how a utility responds to load growth or changing fuel prices. IPM© can also be used to model the detailed dispatch by which a single utility meets its load. IPM© has been used by several ICF Resources clients to address a wide range of questions related to dispatch in many utility systems.

IPM© develops a least cost strategy for a utility to meet its load over a planning horizon within a specified set of financial, environmental, and operations and transmission constraints (see Figure B-1). Utility operations are modeled using a linear programming algorithm. The model is dynamic in that it can generate a simultaneous optimal solution for the entire planning horizon rather than for each year individually. Thus, it combines system capacity expansion planning and unit dispatching decisions to provide the lowest net present value generation costs over the full planning horizon.

Figure B-1



It considers future fuel prices and generation requirements when making decisions for the present, and it simultaneously determines optimal resource utilization given fuel prices, operating characteristics, and constraints.

The model can determine the optimum capacity expansion plan given a set of utility options, demand growth, and reliability criteria. Also, given a capacity expansion schedule, it can determine the optimum utilization of different units given their operating characteristics, fuel prices, and known transmission and operational constraints.

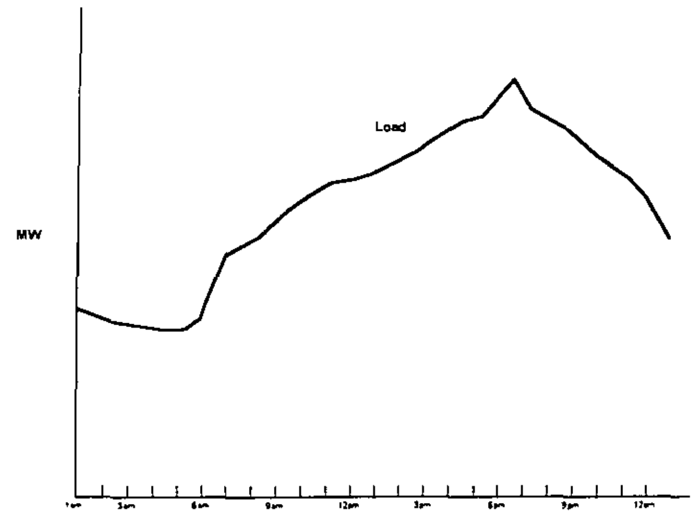
In the real-world, utility loads vary literally every instant. In our analytic approach, this complexity is represented by means of a Load Duration Curve made up of ten analytic segments. *Furthermore, separate* Load Duration Curves are developed for each of three seasons. This approach has many advantages:

- The analytic simplification allows a better representation of inter-regional transmission constraints and the dispatching of hydro units and pumped storage units relative to hourly simulation models. At the same time, our research over the years has shown that, for historical years, our model-based projections match actual conditions with adequate reliability.

- *The costs related to data development and computer processing are modest* enough to allow users to conduct multiple scenario analyses cost-effectively.

ICF Resources' development of the Load Duration Curves is grounded in empirical analysis. Typically, the load on a utility fluctuates from a minimum level in the middle of the night to a maximum level during the afternoon and early evening. Figure B-2 shows a typical daily load shape. When these hourly loads are sorted from highest to lowest, the resulting curve is a "Load Duration Curve" (see Figure B-3). The Load Duration Curve can then be approximated using a step function. IPM© divides a year into a number of "seasons" and uses seasonal Load Duration Curves.

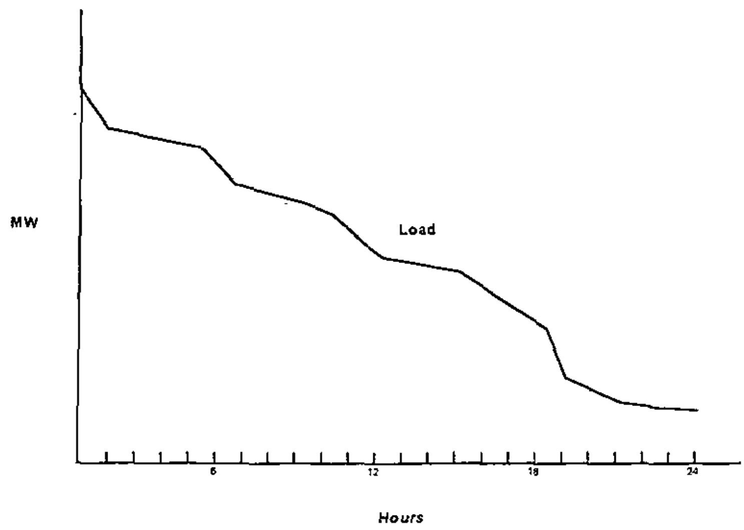
Figure B-2
Typical Daily Load Shape



Load Duration Curves provide a means of integrating hourly unit dispatch decisions over a season. Integrating these decisions across a given season is important when modeling energy limited technologies, such as hydro and pumped storage, as well as purchases with a maximum energy limit, such as off-system purchases. Each of these curves is approximated using 10 steps or load "segments." Figure B-5 shows a typical segmented Load Duration Curve.

Based on the Load Duration Curves, IPM© determines the dispatch of generating units for each segment in each season. That is, it determines which units are operated during each segment (and at what level) to meet the load at minimum cost, subject to various technical constraints (e.g., forced outages, maintenance outages, minimum turndown, etc.). Using these segment-by-segment dispatch patterns along with hourly load data, the model also calculates hourly marginal energy costs.

Figure B-3
Typical Daily Load Duration Curve

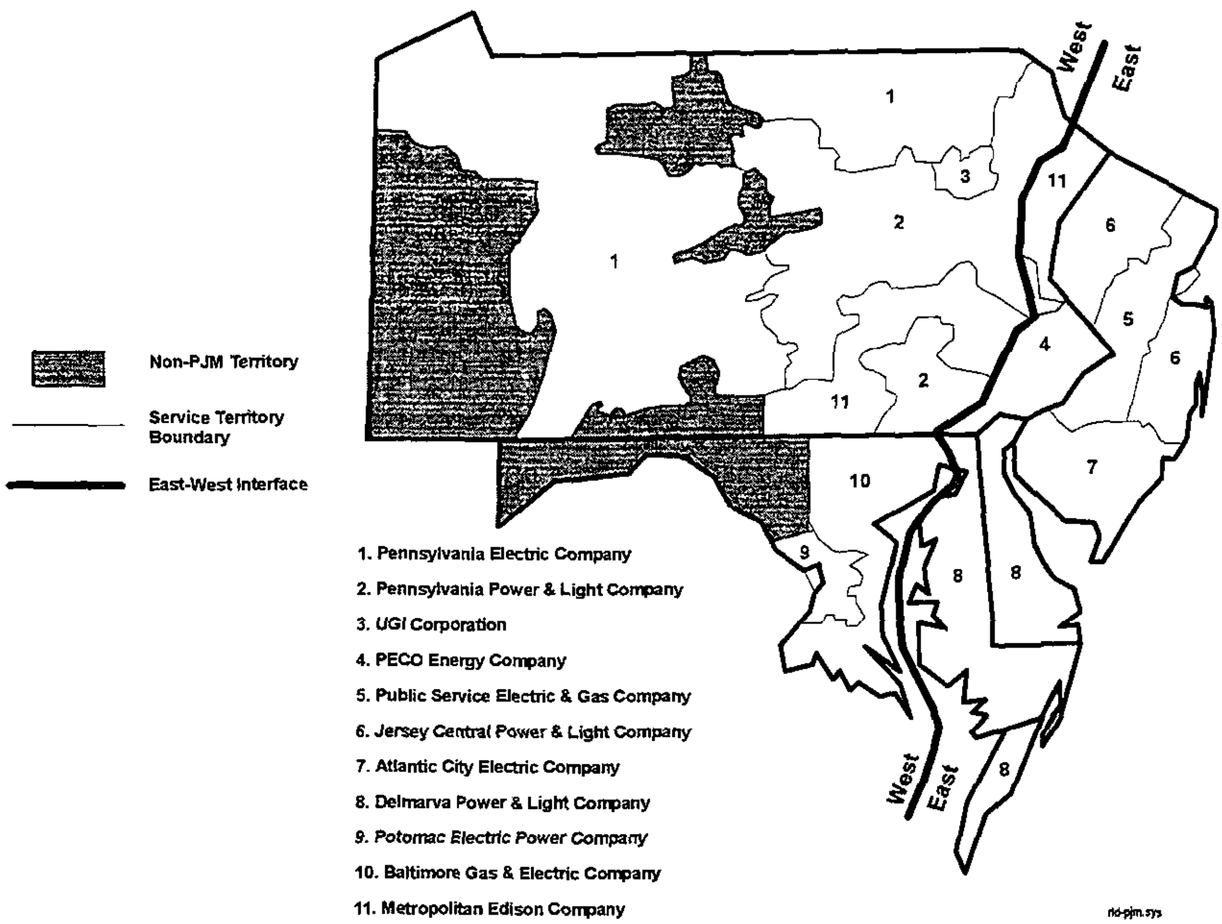


In addition to operating constraints on PJM, such as the must-run constraints discussed above, IPM© takes into account planned outages (i.e., for maintenance), forced outages (i.e., unanticipated shut downs), and unit-by-unit emission constraints. Planned outages can be either specified to correspond with the actual plan of the utility or optimized by the model using the criteria for reserve levelization. Unit-by-unit information on planned outages by season can be provided to IPM© based upon actual operating experience.

Forced outage rates on a unit-by-unit basis are also provided as an input. Because forced outages are not within the control of the utility system, they generally do not vary by season. As in the case of planned outages, forced outage information is based on actual operating experience for existing units. For future units (and QFs), it is based largely on engineering and vendor studies.

The geographic extent of the PJM bulk power market and the major franchised electric utilities within that market is shown in Figure B-4.

FIGURE B-4
THE PJM SYSTEM



For several years, the availability of low variable cost coal capacity over and above local load levels in Western parts of PJM (notably the service territory of Pennsylvania Power & Light) has provided opportunities for the sale of such power to displace high variable cost oil or gas generation in the Eastern parts of PJM (e.g., the service territories of JCP&L and Public Service Electric & Gas in New Jersey). A similar situation exists with respect to the sale of low variable cost, coal-fired power from Allegheny Power System and American Electric Power in the ECAR (East Central Area Reliability) region to utilities in the Eastern part of PJM. The economic incentive to displace high variable cost power with low variable cost power has resulted in a pattern of substantial flow of power from West to East within PJM. Transmission constraints, however, restrict the level of power that can be transmitted between these regions. Therefore, it is useful for analytic purposes to divide PJM into different regions and represent quantitatively the transmission constraints that exist between regions.

Based on *analysis of physical transmission constraints*, ICF Resources divides PJM into the following three regions. (Figure B-4)

- East PJM which includes the service territories of Atlantic Electric, Public Service Electric & Gas, Jersey Central Power & Light, PECO Energy Company, and Delmarva Power & Light.

- West PJM which includes the service territories of Pennsylvania Electric, Metropolitan Edison, and Pennsylvania Power & Light.

- South PJM which includes the service territories of Baltimore Gas & Electric and Potomac Electric Power Company.

The division of PJM into regions has important implications for representing capacity and transmission constraints in IPM. In particular:

Generating Capacity: For analytic purposes the generating capacity included within a PJM region such as, for example, East PJM is the capacity that is actually located in the geographic area covered by that region. Certain *utilities* in the East may, of course, hold shares of capacity that is located in the West (e.g., PECO Energy, an East PJM *utility owns a substantial share* of the Peach Bottom nuclear units 2 and 3, which are a part of West PJM capacity). For purposes of dispatch such capacity is counted as capacity in the West, i.e., the area where it is located. Also, although Jersey Central Power & Light, Pennsylvania Electric, and Metropolitan Edison are all subsidiaries of General Public Utilities ("GPU"), the generating capacity owned by the individual companies is placed in the region in which such capacity is located.

Transmission Constraints: The transmission constraints state, in mathematical terms, the maximum level of power that can be transferred between regions. For example, one transmission constraint provides a mathematical equation for the maximum level of power that can be moved from the West to the East, given a certain level of flow from West to South. The constraints also place absolute bounds on the level of power that can be transmitted from one region to another. By ensuring that the dispatching of plants to meet loads at least cost simultaneously satisfies these transmission constraints, the model-based dispatch mimics the real-world. Based on currently available information, the PJM utilities are not likely to complete any major transmission projects that would mean a substantial change in our assumptions on transmission limits.[1]

Links to Other Regions: The IPM modeling framework for PJM includes all the load and generating resources within the New York Power Pool (NYPP) and the New England Power Pool (NEPOOL). This is achieved by modeling NEPOOL as a region and the NYPP as two regions (Long Island and the rest of NYPP). PJM's interactions with ECAR are represented as a transaction.

[1] The proposed Jersey Central Power & Light (JCPL) and Metropolitan Edison (Met-Ed) energy and capacity purchase from the Duquesne Light Company (Duquesne) included the construction of a 500 kV transmission line between Duquesne and Met-Ed with an expected transfer capability of 1500 MW. This project has, however, been terminated.

SEGMENTING THE LOAD DURATION CURVE

The segmentation of the Load Duration Curve is an important step in IPM-based analyses. The first step in the segmentation process is to analyze the hourly load data, by month, to determine the number of representative seasons per year that are necessary to characterize the seasonal load patterns. Based upon an analysis of hourly load data for PJM, ICF Resources determined that it would be appropriate to divide the year into three seasons: summer, shoulder and winter. Table B-1 shows the combination of months represented in each season.

TABLE B-1
SEASONAL BREAKDOWN IN IPM

Season	Months Included	Hours/Season	Proportions of Year
Summer	June, July, August, September	2,928	33.4%
Shoulder	March, April, May, October, November	3,672	41.9%
Winter	December, January, February	2,160	24.7%
Total		8,760	100.0%

The second step is to divide each season into segments in such a manner that the hours in each segment are very similar in terms of the level of peak load. The actual load for all hours represented in one segment will generally not be identical; however, by carefully splitting the load duration curve into ten segments of varying width, it is possible to achieve an adequate representation of the seasonal load duration curve. The development of the Load Duration Curve for the PJM pool as well as for IPM's East, West, and South PJM is based upon available industry information on load data and load shapes.

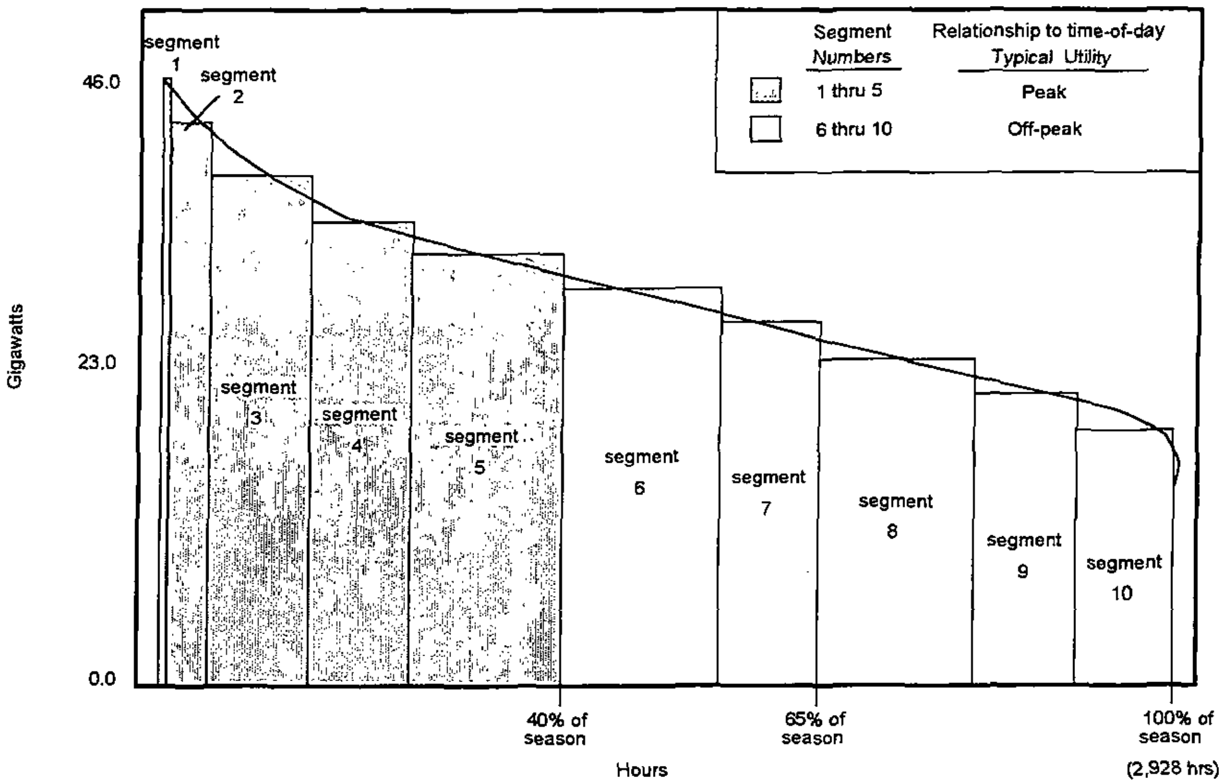
An example of the segmentation of the PJM poolwide load duration curve is shown in Figure B-5. Several points about Figure B-5 are worth noting:

- There are relatively few hours during which demand is at or about the annual peak load (49.0 GW in 1995).
- For 40% of the season, loads were at a level higher than about 33 GW; conversely, for 60% of the hours loads were lower than 33 GW.
- Loads rarely fall below about 15 GW, or 25 percent of the summer peak load.

The shape of the demand curve is important because it is the intersection of demand and available resources (the poolwide supply curve), on an hourly basis, that determines marginal energy costs and, hence, the dispatch of individual resources on the PJM system.

The third step in the segmentation process is to establish the relationship between the *segments and the time-of-day periods.*

Figure B-5
Illustration of Segmentation of the PJM Poolwide Load Duration Curve (Summer Season)



rld-pjm-load.seg

ICF Resources analyzed the hourly observations contained in the seasonal load duration curves such as the one shown in Figure B-5 in order to establish the relationship of segments to time-of-day. This analysis showed that:

- For most PJM utilities, the hourly observations represented in segments 1 through 5 met the peak-hour definitions with a very small number of exceptions. Segments 1 through 5 represent about 40 percent of the hours of the season which is the proportion of annual peak-hours for most PJM *utilities.*

- Segments 6 through 10 generally represent the off-peak hours, which account for about 60 percent of the hours of the season.

UNIT-SPECIFIC DATA

Unit-by-unit information for existing generating capacity is a part of ICF Resources' PJM Generating Unit Data Base, which is one of the major input files provided to the IPM. This comprehensive data base, built and maintained by ICF Resources, contains unit-by-unit information not only on planned outage and forced outage rates, but also on such items as summer capacity, heat rates, variable operation and maintenance costs, and emission limits. For modeling purposes, units in the same model region that possess similar economic and operating characteristics (e.g., similar fuel prices and sources, similar heat rates, similar outage rates, etc.) are combined to yield larger "aggregate units". For example, nuclear plants in East PJM are treated as one large aggregate unit. Aggregation need not sacrifice features specific to individual units. For example, the shutdown of a specific unit can be readily modeled by appropriately reducing the capacity of the corresponding aggregate unit.

ICF's modeling of the PJM system considers certain units as "must-run" units. These include units located close to large load centers that have to be operated whenever available primarily for safety and system stability reasons. The central dispatching entity takes such constraints into account in making the dispatch decision. Also, a large number of QFs have contracts under which the utility is obligated to purchase all power tendered. Regardless of the contract price for power, these QFs are properly considered must-run units.

For technical reasons, some units (e.g., coal-fired steam turbine-based units) cannot be frequently cut back below a certain percent of full load. Therefore, a dispatching entity might need to chose between (a) running such a unit at least at its "minimum turndown" level to allow the option of running harder during times of higher demand (even if such a choice is not in a strict sense the "least cost" option) and, (b) shutting down the unit completely. This constraint often results in certain units running at least at their minimum turndown levels during weekdays (when most utilities experience their peak loads) and being shut down completely during the weekends (which represent the off-peak period for most utilities). In utility parlance, these are "cycling" units.

EMISSION AND ACID RAIN LEGISLATION

Allowable emission rates on a unit-by-unit basis can be provided as an input to the IPM. Currently, these emission rates are determined by the regulatory status of the plant (e.g., plants covered by the New Source Performance Standards ("NSPS") of 1977; plants not covered by any NSPS but subject to State Implementation Plans ("SIPs"); etc.).

The IPM provides a flexible framework to model different acid rain provisions. In particular, each model unit can be provided with a number of compliance options such as scrubbing, coal switching, or allowance purchases at a "market price," and the choice between options can be based upon achieving least cost compliance within the requirements of the law.

ANALYTICAL OUTPUT

Generation has value in both PJM's capacity market and the electric energy market. ICF Resources' competitive price of wholesale electric generation projections are therefore based on separate projections of the competitive price of electric capacity and the competitive price of electric energy, with the total being the sum of the two.

The competitive energy price projections were prepared using ICF Resources' representation of the PJM system using its Integrated Planning Model (IPM©). As discussed above, IPM© utilizes a linear programming algorithm to find an optimal dispatch pattern and choice of resource options to meet electric energy demand at the minimum cost. By overlaying hourly load data onto this dispatch pattern, the model calculated a marginal energy cost, i.e., competitive energy price, for each hour.

The projection of the competitive price of capacity is based upon (i) the forecasted capacity and load balance in PJM and (ii) market information available from recent capacity sales and purchases entered into by PJM utilities. As discussed above, interactions between buyers and sellers in the existing PJM market can be seen as a functioning market. In equilibrium, when capacity and demand are in balance, i.e. when amount of capacity available on the pool is equal to the expected peak plus required capacity reserves, the spot capacity price is set by the cost of installing a combustion turbine. This is because a combustion turbine is the source of new capacity with the lowest capital cost. During periods of excess capacity, the price of capacity is lower, but not zero. This is due to the positive benefit additional capacity creates by lowering the probability of a supply shortage.

PECO STATEMENT NO. 9

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR ISSUANCE OF A QUALIFIED RATE ORDER
UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY

OF

WILLIAM H. HIERONYMUS

REGARDING MARKET PRICES FOR PECO ENERGY GENERATION

DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS

I. QUALIFICATIONS

Q. Please state your name and business address.

A. My name is William H. Hieronymus. My business address is Putnam, Hayes & Bartlett, Inc., One Memorial Drive, Cambridge, Massachusetts 02142.

Q. By whom are you employed?

A. I am a Managing Director of Putnam, Hayes & Bartlett. Inc. (PHB), an economic and management consulting firm with offices in Cambridge, Washington D.C., Palo Alto and Los Angeles.

Q. *What is your educational background and work experience?*

A. I received my bachelor's degree from the University of Iowa in 1965, my master's degree in economics in 1967 and a doctoral degree in economics in 1969 from the University of Michigan, where I was a Woodrow Wilson Fellow and National Science Foundation Fellow. After serving in the U.S. Army, I began my consulting career.

In 1973 I joined Charles River Associates Inc. as a specialist in antitrust economics. By the mid-1970s my focus was principally on the economics of energy and network industries. In 1978 I joined PHB where my consulting practice has focused almost exclusively on network industries, particularly electric utilities.

During the past 23 years, I have completed numerous assignments for electric utilities; state and federal government agencies and regulatory bodies; energy and equipment companies; research organizations and trade associations; independent power producers and investors; international aid and lending agencies; and foreign governments. While I have worked on most economics-related aspects of the utility sector, a major theme has been public policies and their relation to the operation of utility companies.

Since about 1988, the main focus of my consulting has been on electric utility industry restructuring, regulatory innovation and privatization. In that year I began work on the restructuring and privatization of the electric utility industry of the United Kingdom, an assignment on which I worked nearly full time through the completion of the restructuring in 1990. I also led a major study of the reorganization of the New Zealand electricity sector, focusing mainly on competition issues in the generating sector. Following privatization of the UK industry, I continued to work in the United Kingdom for electricity clients based there and I also was involved in restructuring studies concerning the former Soviet Union, eastern Europe, the European Union and specific European countries.

Late in 1993, I returned to the United States, where I have worked on the restructuring, regulatory reform and increasingly competitive future of the US electricity industry.

I have testified before state and federal regulatory bodies, legislative bodies and federal courts on numerous occasions, principally on electric utility matters but also on antitrust and civil litigation. I have testified before the Pennsylvania PUC as an expert on various aspects of utility economics on behalf of PECO Energy (PECO), Pennsylvania Power and Light, Penn Power and Peoples Natural Gas on numerous occasions.

My resume is attached as Exhibit WHH-1.

II. INTRODUCTION AND SUMMARY

Q. What is the purpose of your testimony?

A. I have been asked by PECO to provide unit-by-unit estimates of market revenues that contribute to covering fixed costs, overhead and profits for each of its generating units or unit entitlements. More specifically, I have provided, for each unit and for the period 1999 to 2015, estimates of annual average prices of energy and capacity sold, the amount of energy and capacity sold and the fuel and variable operations and maintenance expense (O&M) required to produce the forecasted amount of energy. Estimates for the totality of PECO's generation are provided in Exhibit WHH-2, with a unit-by-unit summary in a later exhibit. Exhibit WHH-2 shows that revenues per MWh generated rise quickly from less than $25 per MWh in 1999 to nearly $35 per MWh in 2001 due principally to tightening of the capacity market. They then rise much more gradually to about $60 per MWh in 2015.

Q. How is your testimony organized?

A. After this introduction, my testimony is organized into three sections. First, I discuss the revenue estimates. Second, I discuss the costs estimates. Third, I discuss the GE MAPS model, upon which I relied for most of the revenues and cost estimates, as well as the sources of inputs used to run the model.

III. REVENUE PROJECTIONS

Q. *What estimates of revenues did you provide?*

A. *I provided estimates of energy and capacity revenues for each generating unit for the years* 1999 through 2015.

Q. How did you estimate energy revenues?

A. I used the General Electric Multi-Area Production Simulation Program (GE MAPS) model to estimate energy revenues for each generating unit. As described more fully below, the GE MAPS model is a transmission and generation dispatch model that simulates the central dispatch of a region, in this case PJM (and flows into and out of it from adjacent regions), taking into account any transmission limitations that may arise from economic dispatch. While these formally are "spot" prices, they are an equally valid forecast of prices for energy sold under bilateral contracts. The outputs of the GE MAPS model include the locational spot price for each generation unit per hour and the generation (in kilowatt-hours) of each generating unit per hour. Energy revenues in a year are calculated as the locational spot price for the generator in an hour times the generation in that hour, summed across all the hours in the year. As discussed briefly below, revenues earned by units that run in any commitment cycle were, at a minimum, sufficient to recover full incremental costs over the cycle.

Q. For what years did you run GE MAPS?

A. I ran GE MAPS for 1999, 2004, and 2009. I did not run GE MAPS for other years because each run takes a long time, because the outputs are voluminous, and because I felt that I could represent the entire period well with these three years.

Q. How did you develop revenue and cost estimates for the years between 1999 and 2004, 2004 and 2009, and 2009 and 2015?

A. Between 1999 and 2004, I interpolated; specifically, I projected that the revenues and costs changed in constant annual percentages from the 1999 estimate to the 2004 estimate. I did the same for the period between 2004 and 2009. From 2009 to 2015, I assumed that energy revenues would increase at the same rate as the price of natural gas, since natural gas becomes increasingly on the margin in this period. Since gas escalates at a higher rate than other fuels, the assumption that the price in all hours escalates at the gas price will tend to somewhat over-state the rate of post-2009 revenue escalation. I projected that capacity revenues would increase with the rate of inflation (the GDP implicit deflator). I projected that fuel costs would increase at the DRI forecasted escalation rate for each fuel - coal costs at the rate for coal, gas costs at the rate for gas, and oil costs at the rate for oil. I projected that variable operations and maintenance costs would increase at the rate of inflation.

Q. Have you provided forecasts of costs and revenues beyond 2015?

A. No. However, I understand that PECO needs to make projections also for the years 2016 through 2029 to value units projected to remain in service into this period. Given the very considerable uncertainties about fuels markets, environmental requirements and technological change so far into the future, my best advice to PECO is to project that costs and revenues will increase at the rate of inflation.

Q. What was assumed about capacity additions and closures over this period?

A. I projected that all existing capacity would remain open. Based on that assumption, I then determined how much new capacity would be needed to meet a reserve requirement of 18 percent for the PJM, New York (NYPP) and New England (NEPOOL) power pools, and capacity was added to meet this requirement. I believe this to be a reasonable estimate of reserve requirements for these pools in these periods; if anything, it is likely to overstate the requirement for capacity (and hence the rapidity with which capacity value rises to the cost of entry) since market restructuring is likely to lead to more customers receiving real time prices and a consequent reduction in the peak loads currently being forecasted. New capacity was needed in PJM and NEPOOL by the 2004 energy market simulation and in NYPP by the 2009 energy market simulation. Based on an assessment of plant economics, I concluded that in each case the appropriate capacity type to add was modern gas-fired combined cycle units. Generally, capacity was added in areas with the highest prices since this is where merchant plants would earn the highest revenues.

Q. How did you assume that energy would be bid into the PJM interchange and outside pools that you modeled?

A. I assumed that each block of power from each unit would be bid at marginal cost -- fuel plus variable O&M. This is the conventional assumption in modeling dispatch and is consistent with competitive generator behavior. A competitive generator who receives, as we assume, market prices rather than its bid price will bid at marginal cost. If it bids higher, it risks not being dispatched when it would be profitable. If it bids lower, it risks being run at a loss.

Q. You indicated that revenues for each unit were derived on the basis of hour-by-hour spot prices at the generator's location. How were these spot prices derived?

A. The GE MAPS model, simulating the behavior of an independent system operator, commits and dispatches the available units to minimize total system costs. If there are no transmission constraints, the market price across the system will be the same and would be the cost of the highest unit required to meet load, often called the "system Lambda".

If there are transmission constraints, then the price will not be uniform. Some low cost power will not be able to flow to areas in which the remaining available generation has higher variable costs. As a result, the price in the high cost area will be set by local generation and will be higher than if there are no constraints. Conversely, prices in the areas with a surplus of lower cost generation that cannot be transmitted to the high cost area will be lower than if transmission were unconstrained.

Q. Did you find transmission constraints in PJM?

A. Yes. The GE MAPS model reveals that, as the system would be operated in 1999-2009 conditions, there are three key sets of constraints within PJM. There is a constraint at the western interface, which is just east of the Keystone and Conemaugh stations and limits the flow of power from western Pennsylvania and ECAR (the reliability council west of PJM) into the rest of PJM. There is a constraint at the central/southern interface, which runs approximately along the southern border of Pennsylvania from the east and then north slightly west of Harrisburg and limits the flow of power from southern and western PJM and from ECAR into the rest of PJM. There is a constraint at the eastern interface which runs just west of PECO's service territory and limits the flow of power to PECO and the rest of eastern PJM. Our simulations show that, at times, one (or more) of these interface constraints is binding.

Q. What is the effect of these constraints on the locational spot prices that would be paid to PECO's generating units?

A. The effect is to increase the prices paid to PECO's generating units in eastern PJM and to decrease the prices paid to Keystone and Conemaugh. If these constraints did not bind, the prices paid to PECO's generating units in eastern PJM would be lower and the prices paid to Keystone and Conemaugh would be higher. On balance, this increases the revenues earned by PECO units relative to an unconstrained case.

Q. Does the assumption that all generation receives the spot energy price at its location depend on the pool rules adopted for the PJM Interchange?

A. Not importantly. While we modeled prices earned by PECO generating units based on locational spot prices partly for convenience, since this is the architecture of the GE MAPS model, I also believe that locational spot prices will vary by location to reflect the impact of constraints. Quite simply, in a constrained area buyers of contract or spot energy will not have energy from outside the constraint available as an alternative to serve incremental load. Prices will reflect supply and demand conditions inside the constraint, hence the marginal price in the constrained area. Similarly, when constraints keep low cost energy from flowing out of an area, suppliers will have to compete to meet the local load and prices will be lower.

Q. Do any of PECO's units fail to recover their out of pocket generating costs if bids are based on marginal costs?

A. Had we not adjusted revenues to assure that out of pocket costs were recovered (for example, in "uplift"), some of PECO's mid-merit steam units would not have recovered all costs on some days. The possibility of negative cost recovery occurs if a unit with start up and no load costs is run for few hours and the difference between its cost and market prices in those hours is low. This clearly is not in the interest of the unit's owner, and the problem will be resolved either through pool rules or through the owner increasing its bid costs until the unit either is not committed or revenues earned are high enough to recover out of pocket costs when it is. To reflect this, I had the cycles with negative cost recovery identified and increased revenues for the specific generating units sufficiently to eliminate losses. These adjustments add only about 0.1 mills per kWh to the price received by PECO for its generation.

Q. How did you estimate capacity revenues?

A. The market value of capacity will be determined by conditions of supply and demand. Currently, capacity is in excess supply in PJM. Recent transactions indicate that the market price of capacity in PJM currently is approximately $15 per kilowatt-year. Changes in supply and demand between now and 1999 are unlikely to change that price materially. Hence, I have used that price, adjusted for inflation, as the capacity price in 1999.

Based on the OE-411 form filed by MAAC in 1996, an 18 percent reserve requirement would require new capacity in PJM by about 2001. Hence, the 2001 revenues earned by new generation will have to rise to a level sufficient to make capacity economic, since no market participant would build it otherwise. The price of capacity in 2001 may have to rise to the level of the annualized cost of a simple cycle combustion turbine peaking unit, which is about $45 per kilowatt year in 1996 dollars. It may be less; I had indicated that the most economic capacity to build in PJM is a combined cycle unit. This is because its energy market profits are more than sufficient to offset the higher capital cost of this type of unit. Nevertheless, I conservatively have projected that the price of capacity in 2001, and subsequently, will be the annualized cost of a new peaking unit. Between 1999 and 2001 (i.e. for 2000) I interpolated between the current market price of capacity and the 2001 price.

This capacity price is applied to all of PECO's capacity. In electricity systems in which market mechanisms included a separately priced value of capacity (which include both the current and proposed PJM interchange) all capacity that meets availability requirements receives, implicitly or explicitly, market value of capacity.

Q. You have based your calculation of revenues earned by PECO's generating units on *the spot price of energy plus the estimated market value of capacity.* In your *opinion*, is PECO likely to receive higher revenues if it sells energy and capacity under bilateral contracts?

A. No. The only reason why the value of a contract might differ from the expected value of spot revenues is that a contract provides greater price certainty. This hedging function of contracts is valuable to both buyers and sellers. There is no reason in fact or theory to assume that contracts will systematically result in higher revenues. For example, in the UK I assisted load-serving buyers in evaluating contract offers. The analysis performed by buyers always was based on the expected value of the spot market and accorded no premium to price certainty. Moreover, over the last several years, new contract prices and spot prices in the UK market have been at very similar levels.

IV. GENERATION COST PROJECTIONS

Q. What cost forecasts did you provide to PECO?

A. I provided estimates of fuel costs and variable costs for each generating unit.

Q. How did you estimate fuel costs?

A. I used the GE MAPS model to estimate fuel costs for each generating unit. The fuel costs for a unit are calculated from its generation, its heat rate (which varies with generation), and the fuel price for that unit. The sources of these inputs are described later in my testimony.

Q. How did you estimate variable operations and maintenance costs for each unit?

A. I used the GE MAPS model to estimate the variable operations and maintenance costs for each generating unit. These are calculated by multiplying input values for variable operations and maintenance cost per kilowatt-hour by the kilowatt-hours of generation by the unit.

V. THE GE MAPS MODEL AND COST INPUTS

Q. What is the GE MAPS model?

A. The GE MAPS model was developed and is licensed by the General Electric Company. A description of this model is provided in Exhibit WHH-5. Like other production costing models, GE MAPS will commit and dispatch generating units based on bid or cost data for each generating unit. Its more unique capability is in taking into account transmission constraints when it does unit commitment and dispatch. It is this capability that caused me to prefer it for modeling prices in PJM. Transmission constraints can and will have significant effects on the unit commitment and dispatch decisions of the Independent System Operator. As a result of its ability to incorporate properly the effects of transmission constraints, the GE MAPS model can forecast locational spot prices for each generating unit. This capability is critical to the ability to forecast generating revenues that are based on locational spot prices.

Q. What are the outputs of GE MAPS?

A. There are many outputs of GE MAPS. These include for each generating unit locational spot prices, generation, fuel costs, and variable operations and maintenance costs by hour. From these outputs, net negative cycle costs also can be calculated and then summed to estimate uplift revenues. The GE MAPS outputs also quantify transmission flows over the transmission network and the shadow price associated with any transmission constraint, by hour. The outputs of the GE MAPS model (set up for this analysis) also include transmission flows between three power pools - PJM, NYPP, and NEPOOL - and also imports from ECAR, Hydro Quebec, and Ontario Hydro.

Q. What are the inputs to GE MAPS?

A. There are many inputs to GE MAPS, which can be separated into five categories. The first category includes generating unit characteristics, including such parameters as capacity, heat rates by unit block, ownership, variable operations and maintenance costs, planned maintenance, and forced outage rates. A second category includes fuel prices, SOx offset costs, and NOx offset costs, where these are specified as a base year price and then escalated from the base year prices. A third category includes loads, load shapes, and load growth for the various load buses. A fourth category includes transmission data, including transmission constraints and shift factors which capture the effect of a generating unit on various elements of the transmission network. A fifth category includes other key inputs such as potential imports from ECAR, Ontario Hydro, and Hydro Quebec, wheeling rates between pools, and transmission rates within pools.

Q. **What are the sources for these inputs?**

A. GE already possessed, and provided to us, a data base that it had derived from various internal and public sources. This database is a commercial product of GE's. Under my direction, PHB staff reviewed this data base and, where necessary, made adjustments to it. I will discuss these refinements later in my testimony.

Q. **Did the GE data base provide information of future units required to meet reserve requirements in PJM, NYPP and NEPOOL?**

A. No. The GE data base was not set up for simulation of a period as long as required for this study. As noted earlier, our assessment of the economics of the northeastern US electricity market caused us to conclude that the capacity that most cost-effectively would be added is combined cycle gas capacity. The operating characteristics, amount and timing of the units we added are shown on Exhibit WHH-3, page 2.

Q. **Did PHB change the variable operations and maintenance cost estimates provided by GE?**

A. No. We reviewed these estimates, but we did not change them. We note from the level of these estimates that GE holds the view that most of the non-fuel O&M costs at a generating unit are fixed and do not change with the level of generation. This is the most common view, and one with which I agree. I should note, however, that some utilities treat a significantly higher proportion of costs as variable. Exhibit WHH-3, page 3, provides the variable operations and maintenance costs estimates from GE.

Q. Did PHB adjust the heat rates provided by GE?

A. Yes. The GE heat rates are design heat rates, based on the technical specifications of each generating unit. In many cases, design heat rates are lower than the heat rates actually achieved by utilities. It may be reasonable to assume that competition will cause utilities to reduce heat rates from current levels. That is what I understand that the generators in the UK have been able to achieve. However, it may be too optimistic to assume that design heat rates can be achieved on a basis that is both economic and preserves unit reliability. To make allowance for this, we increased the GE-provided fossil plant heat rates by 5 percent. The effect of this change is to increase incremental generating costs for fossil plants by about 5 percent. Since fossil plants almost always set spot market energy prices, the effect is to increase PECO's forecasted energy revenues by a similar 5 percent relative to what would have been forecasted without the change. It also increases its fossil energy costs by nearly comparable amounts. However, this does not fully offset the revenue increase since much of PECO's energy comes from nuclear units. Hence, the result of this change is to increase PECO's operating profits in energy markets and reduce the consequent estimate of its strandable costs.

Also, PECO informs me that the full load heat rate at Eddystone 1 & 2 is 10,500 btu per kWh, materially higher than the GE estimate of less than 9000. Eddystone was designed as an extremely efficient plant. However, it did not operate reliably at design efficiency, and reliable operation resulted in reduced efficiency. Further, scrubbers were subsequently added to these units, and the scrubbers reduced the efficiency further. On this basis, I have reduced the efficiency of Eddystone 1 and 2 to actual levels. Heat rates for similar fossil-steam units owned by other utilities were increased by 10 percent. This, of course, reduces the value of the facilities.

Q. **What changes did PHB make to the second category of data - fuel prices and environmental offset costs?**

A. We reviewed these data against other data sources. Where necessary, we modified the data received from GE, correcting errors and incorporating other information, such as information on spot market fuel prices. This somewhat revised GE data base provided base year fuel costs. Fuels cost escalation over the study period was on the basis of a 1996 forecast by DRI, provided to us by PECO. Exhibit WHH-3, pages 4 and 5 show the DRI forecast and representative prices for PECO units. The cost of environmental offsets was estimated by PHB on the basis of in-house studies. These also are shown on Page 5 of Exhibit WHH-3.

Q. **Did PHB make changes to the third category of data - loads, load shapes, and load growth?**

A. No. We relied entirely on the GE data. The GE data in turn are based principally on the EIA Form OE-411 forecasts of load provided by the two reliability councils that were modeled, these being the Northeast Power Coordinating Council (NYPP and NEPOOL) and the Mid-Atlantic Area Council (PJM).

Q. Were changes made to the transmission data contained in the commercial version of the GE MAPS model?

A. No.

Q. What was the source of the fifth category of data - potential imports and wheeling rates?

A. The GE MAPS model and data that I used include explicit modeling of PJM and well as the New York and New England power pools. For this reason, no assumptions had to be made concerning the cost of, and constraints affecting, inter-pool transactions among them; imports and exports were forecasted by the model based on economics and transmission limitations. GE had not incorporated data on imports available from ECAR or from Ontario Hydro and Hydro Quebec. These data inputs were created by PHB as a part of on-going projects for various clients in the northeastern US and reflect PHB fact-finding and analysis. These also are shown on pages 6 and 7 of Exhibit WHH-3.

Q. Do you have an Exhibit that shows the unit by unit revenue and cost data that you provided to PECO?

A. Yes. These data are shown on Exhibit WHH-4.

Q. Does this conclude your testimony?

A. Yes.

WILLIAM H. HIERONYMUS **Managing Director**

William Hieronymus has consulted extensively to managers of electricity and gas companies, their counsel, regulators and policymakers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy and regulatory issues. He has spent the last several years working on restructuring and privatization of utility systems internationally and on changing regulatory systems and management strategies in mature electricity systems such as the United State's. In his twenty years of consulting to this sector he also has performed a number of more specific functional tasks including the selection of investments, determining procedures for contracting with independent power producers, assistance in contract negotiation, tariff formation, demand forecasting and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of utility clients before regulatory bodies, federal courts and legislative bodies in the United States and the United Kingdom. Since joining Putnam, Hayes & Bartlett, Inc. (PHB) in 1978 he has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION AND RELATED MANAGEMENT AND PLANNING ISSUES

- Since 1993, when he returned to the United States, Dr. Hieronymus has been deeply involved in assignments for utilities that are seeking to shape or respond to new competitive forces and changes in regulation of the electric utility industry. He is advising utility clients on a confidential basis in their analyses of the likely future, and on ways of quantifying and recovering costs that may be stranded by expanded wholesale and retail market access. For one Northeastern utility, he co-wrote their response to a Commission docket on the treatment of stranded costs. He participated in PHB's consultation to a Massachusetts project organized by the Governor's office designed to bring together legislators, regulators, utilities and intervenors to consider appropriate forms of incentive regulation and roles for competition. He is advising two midwestern utilities on incentive ratemaking proposals and, in one of the two cases, is preparing the related submission for its rate case. He also is advisor to an ECAR utility where the main focus of his work is changes in pricing and marketing strategies in an increasingly open competitive market.

- Beginning in 1988, following promulgation of the White Paper setting out the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus has advised the Regional Electricity Companies concerning negotiations with the Government over the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators.

- In addition to his participation in the central process of creating the UK electricity privatization and reform he has consulted extensively to utilities as they adapted to the changed structure. During the preparation for electricity privatization in the U.K., he assisted several of the individual electricity companies in understanding the evolving system, in development of use of system tariffs, and in developing strategic plans and management and technical capabilities in power purchasing and contracting. He continues to advise a number of clients, including regional companies, power developers, large industrial customers and financial institutions on the U.K. power system. He was extensively involved in helping senior management at one of the regional electricity companies in preparing their filings for the 1993 and 1994 price control reviews of the supply and distribution businesses, including development of innovative benchmark features that were adopted by the regulator, and in negotiations with the regulatory authority.

- Also in the United Kingdom, Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for the Teeside power station, an 1,825 megawatt combined cycle gas station. He also has assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- He also has consulted on the separate reorganization and privatization of the Scottish electricity sector. PHB's role in that privatization included advising the largest of the two Scottish companies and, through them, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation and company strategy.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, he developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command and control system to a decentralized, corporatized system. A main feature of the contractual system developed was to separate the functions of government as the owner and regulator of the power sector and to create regulated contracts that compensated generators on the basis of the value of production and availability rather than cost reimbursement.

- For Iberdrola, the largest investor-owned Spanish electricity company, he has assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation and the phasing out of subsidies.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian electricity Ministry, the goal of which is to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. He continues to participate in PHB's advisory assistance to the Ukraine, which is now funded by the U.K. Know How fund and the World Bank. The restructuring and privatization of the industry are now in the implementation phase.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, he has continued to advise the Russian energy and power ministry, MINTOPENERGO and the successor corporatized utility.

- On behalf of a large continental electricity company he has analyzed the directives from the European Commission on electricity transit and on the internal market for electricity. The purpose of this assignment is to develop forecasts of likely developments in the structure and regulation of the electricity sector in the common market.

- For electricity clients in the United Kingdom, he has analyzed the evolving environmental regulations of the European Commission and the government of the United Kingdom in order to forecast the effects on electricity prices and the economics of alternative generation investments.
- For a task force representing the Treasury, electric generating and electricity distribution industries in New Zealand, he undertook an analysis of industry structure and regulatory alternatives for achieving economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and implications for asset valuation, electricity pricing, competition and regulatory requirements.
- For the European Bank for Reconstruction and Development he has performed a number of studies of the electricity sector of Slovakia. These have been used by the Bank in making decisions concerning equity investments in electricity generation and in energy intensive industrial facilities.
- For an East Coast electricity holding company, he prepared an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand management programs. The analysis formed the basis for his testimony in a generic proceeding concerning both the regulation of conventional utility generation investments and customer-side-of-the-meter programs.
- In connection with base load plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico and before the Federal Energy Regulatory Commission in plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant cost for tariff setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support and assistance in writing briefs.
- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing base load plants that are currently under construction. His testimony has covered the likely cost of plant completion, forecasts of operating performance and extensive analyses of ratepayer and shareholder impacts of completion, deferral and cancellation. Frequently, this testimony has involved detailed rebuttal of intervenor analysis methods and assumptions concerning financial impacts of completion or cancellation and relative costs of coal or conservation alternatives.
- For U.S. utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments in support of strategic decisions concerning the construction projects. Areas of inquiry included plant cost, the financial feasibility of the construction program, power marketing opportunities, the impact of potential regulatory treatments of plant cost on shareholders and customers and evaluation of offers to purchase partially completed facilities.

WILLIAM H. HIERONYMUS
Managing Director

- For the electric utility company of The Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a major midwestern utility, he headed a team that assisted senior management in devising its strategic plans including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition and diversification opportunities.

- On behalf of two West Coast utilities, he testified in rebuttal to commission staff and intervenors in a needs certification hearing for a major coal-fired generation complex. His testimony discussed the proper type of economic analysis to be used in determining whether the plant at issue was cost-effective relative to available alternatives. Based on simulation of life-cycle revenue requirements for the various alternative supply plans, he concluded that the complex was cost-effective irrespective of disputed issues concerning the cost and availability of alternatives.

- For a large U.S. utility, Dr. Hieronymus participated in a major 18-month effort to provide it with an integrated planning and rate case management system. His specific responsibilities included assisting the client in design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts and forecasts of the impacts of conservation and load management programs.

- For two midwestern utilities, he prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee with respect to the potential for utilizing conservation and solar and alternative forms of energy production to displace planned central-station generation.

- For a major U.S. combination electric and gas utility, he directed the adaptation of a PHB-developed financial simulation model for use in resource planning and evaluation of conservation programs.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus has participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies and prices for transmission pricing. These studies have spanned both short run marginal cost and long run marginal cost methodologies for regional pricing and the pricing of transmission access in transmission constrained areas. The studies also have considered regulatory improvements to reward the transmission company for cost-effective investments.

- In preparation for full retail access in the United Kingdom he has reviewed the tariff and contract pricing structures of one of the regional electricity companies and assisted them in developing a strategy for moving tariffs to the levels that will be required once the market is fully competitive.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes. The study was used to satisfy a portion of the utility's PURPA 133 filing.

- For EPRI, he directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, Dr. Hieronymus developed a methodology for designing optimum cost-tracking block rate structures. The methodology was then applied to determine the optimum rate structure for a particular utility. The block rate structure was evaluated relative to optimum time-differentiated and demand rates.
- On behalf of a group of cogenerators, he filed testimony before a committee of the United Kingdom on U.S. cogeneration pricing practices and on the effect of prices on U.S. cogeneration supply.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines on fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guideline on cost-of-service standards.
- For private utility clients, he assisted in the preparation of comments on draft Federal Energy Regulatory Commission (FERC) regulations and in preparing their compliance plans for PURPA Section I33.
- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act of 1978. The report focused on the relationship between those purposes and cost-of-service and ratemaking positions under consideration in the generic hearings required by PURPA.
- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.
- For the U.S. Department of Energy (DOE) he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on the efficiency incentive effects of specific types of fuel and purchased power clauses.
- For counsel to a utility involved in an avoided cost pricing proceeding, Dr. Hieronymus provided analytic support in cross-examining opposing witnesses and developing briefs.
- For the commissioners of a public utility commission, he assisted in preparation of briefing papers, lines of questioning and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force and formed an important basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.
- For a large eastern utility, he developed a load forecasting model designed to interface with the utility's revenue forecasting system- planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.
- For the DOE, he directed the development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and constructed a forecasting model for their interim use.
- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area level forecasting models of electric utility companies.
- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.
- For a midwestern electric utility, he has provided consulting assistance in improving its load forecast and has testified in defense of the revised forecasting models.
- For an East Coast gas utility, he testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These include both Sherman Act Section One and Two cases, contract negotiations, generic rate hearings, ITC hearings and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. He also has testified on damages in two cases involving a supplier of electricity generating equipment.
- For a private client, he headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.

- For a industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, he developed an estimate *of the potential market for the system by geographic area.*

Dr. Hieronymus has addressed a number of conferences on such issues as utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation and utility-related opportunities for investment bankers.

Before joining PHB, Dr. Hieronymus was program manager for Energy Market Analysis at Charles River Associates. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving in the U.S. Army. He is a present or past member of the American Economics Association and the International Association of Energy Economists, and a past member of the Task Force on Coal Supply of the New England Energy Policy Commission. He is the author of numerous reports and papers in the field of energy economics.

Dr. Hieronymus received his B.A. from the University of Iowa and his M.A. and Ph.D. degrees in economics from the University of Michigan.

SUMMARY OF FINDINGS

	Average Market Price $/MWh	Average Fuel Cost $/MWh
1999	24.2	8.4
2000	28.1	8.6
2001	34.4	8.9
2002	35.9	9.3
2003	37.4	9.6
2004	39.0	10.1
2005	40.5	10.4
2006	42.1	10.8
2007	43.7	11.3
2008	45.4	11.7
2009	47.3	12.2
2010	49.1	12.6
2011	51.0	13.1
2012	53.0	13.5
2013	55.0	14.0
2014	57.2	14.5
2015	59.4	15.0

PJM Energy Demand

Year	Energy Demand (1000 GWh)
1999	256,675
2004	276,437
2009	289,059

New Capacity

New gas-fired combined cycle units were added to maintain an 18% reserve margin in each of the three pools. The characteristics of these units are shown below:

New Combined-Cycle Characteristics

Parameter	
Unit size	375 MW
Full load heat rate	7,300 Btu/kWh
Variable O&M	$1.0/MWh

The following are the number of combined cycle units added:

Capacity Additions (Number of 375 MW Units)

Pool	1999	2004	2009
PJM	0	9	7
NEPOOL	0	1	5
NYPP	0	0	4

Unit Variable Operating and Maintenance Costs

The following general rules were applied by GE in specifying variable operating and maintenance costs. There are some minor differences from this pattern in the database.

Unit Type	Variable O&M (1996$/MWh)
Nuclear units	0.60
Coal units	2.00
Gas-fired units	1.25
Residual oil units	1.92
Distillate oil units	1.50

Sample Delivered Fuel Prices ($/mmBtu)

Fuel Prices

An assessment of fuels that are likely to be used by generating units was made (including the sulfur content of the fuel). Current market price estimates for fuels delivered to these units or to nearby units was used as a starting point for fuel prices. All coal, gas and oil prices were revised.

Current fuel prices were escalated to future year (nominal) prices using DRI price escalators.[1]

CROMBY COAL PRICES

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
2004	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60	1.60
2009	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80

CONEMAUGH COAL PRICES

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
2004	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
2009	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35

CROMBY NATURAL GAS PRICES

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	2.77	2.66	2.55	2.45	2.34	2.34	2.34	2.45	2.45	2.55	2.66	2.77
2004	3.64	3.50	3.36	3.22	3.08	3.08	3.08	3.22	3.22	3.36	3.50	3.64
2009	4.69	4.51	4.33	4.15	3.97	3.97	3.97	4.15	4.15	4.33	4.51	4.69

EDDYSTONE RESIDUAL FUEL OIL PRICES

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	3.00	2.89	2.73	2.58	2.45	2.45	2.45	2.58	2.73	2.86	2.97	3.00
2004	4.07	3.93	3.71	3.51	3.32	3.32	3.32	3.51	3.71	3.89	4.03	4.07
2009	5.47	5.28	4.99	4.72	4.46	4.46	4.46	4.72	4.99	5.22	5.41	5.47

[1] Data Resources Inc.

SCHUYKILL DISTILLATE FUEL OIL PRICES

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1999	4.93	4.71	4.49	4.22	4.05	4.05	4.05	4.22	4.49	4.71	4.93	4.93
2004	6.57	6.28	5.99	5.62	5.40	5.40	5.40	5.62	5.99	6.28	6.57	6.57
2009	8.69	8.30	7.92	7.43	7.14	7.14	7.14	7.43	7.92	8.30	8.69	8.69

Cost of SO_2 and NO_x Allowances

SO_2 and NO_x allowance prices were estimated and added to oil, gas and coal prices based on the following assumptions:

Allowance Prices ($/Ton)

Year	$/Ton SO_2	$/Ton NO_x
1999	150	1,000
2004	250	1,500
2009	400	1,500

NO_x allowances were added during the "summer ozone season," May - September only.

The following generic NO_x cost adders were assumed, based on average assumed emission rates by plant type in the future:

NO_x Cost Adders ($/mmBtu)

Fuel Type	1999	2004	2009
Coal	0.15	0.15	0.15
Gas	0.05	0.075	0.075
Oil	0.1	0.15	0.15

In 2004 and 2009, coal prices were also increased by the equivalent of $1/MWh in the summer ozone season to account for the additional variable cost of pollution control equipment.

NO_x allowance costs are added to all units. SO_2 allowance costs only apply to some coal units in PJM, NEPOOL and NYPP prior to 2000. Beginning in 2000, all coal and oil-steam units greater than 25 MW would require SO_2 allowances.

Imports and Wheeling Rates

Wheeling Rates

- Each pool (PJM, NYPP, and NEPOOL) was assumed to have no internal wheeling rate
- Wheeling costs between pools were assumed to be $2/MWh

Firm Import Potential

- PEPCO imports 450 MW from Ohio Edison. This is priced at $10/MWh and is available all the time.
- The Hydro Quebec Phase II contract is modeled as 1500 MW maximum with an energy limit of 280,000 MWh per month for January - March and November - December, and 800,000 MWh per month for April - October.

Economy Import Potential

Ontario Hydro to NYPP

Ontario Hydro supply is available 7 am to 10 pm weekdays at 240 MW. It is priced at $23.07/MWh in 1999, $26.75/MWh in 2004 and $31.01/MWh in 2009.

Hydro Quebec Economy to NYPP and NEPOOL

Hydro Quebec supply over and above firm commitments was estimated as 3000 MW in 1999, 1300 MW in 2004 and 0 MW in 2009. This supply is available in NEPOOL and NYPP (with a joint limit). In addition, the supply from Hydro Quebec to NEPOOL from the Phase II contract and economy (the sum thereof) is limited to 2000 MW.

Energy is priced at $16.39/MWh, $19.00/MWh and 22.02/MWh in 1999, 2004 and 2009, resp. It is available 7 am to 10 pm weekdays

ECAR to PJM

ECAR supply curves was estimated for each month for on- and off-peak periods. Average prices for 800 MW blocks were calculated. The monthly on- and off-peak prices are shown below.

1999 Off-Peak

Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
17.50	17.96	17.17	16.73	16.58	16.73	17.29	17.97	16.58	16.58	17.41	17.88
17.85	18.29	17.40	16.97	16.83	17.34	17.88	18.57	16.97	16.95	17.46	18.29
18.15	18.57	17.41	17.17	16.95	17.41	18.29	18.57	17.17	17.04	17.74	18.57
18.34	18.61	17.50	17.34	17.04	17.55	18.57	19.00	17.34	17.29	17.96	18.60
18.57	18.86	17.85	17.40	17.29	17.91	18.60	19.30	17.40	17.40	18.29	18.86

1999 On-Peak

Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
20.12	20.43	18.57	18.29	18.08	20.52	23.71	33.86	18.57	18.29	18.60	20.12
20.52	20.66	18.63	18.57	18.57	20.83	25.24	33.86	18.60	18.57	19.11	20.52
20.83	20.87	19.11	18.82	18.59	21.11	28.46	34.86	19.39	18.85	19.78	20.81
20.99	21.07	19.39	19.07	18.97	21.44	28.82	34.86	19.57	19.16	20.22	20.94
21.11	21.44	19.71	19.16	19.13	22.76	32.46	34.86	19.89	19.30	20.52	21.11

2004 Off-Peak

Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
20.78	21.44	20.55	19.49	19.01	20.44	20.74	22.53	19.49	19.40	20.73	21.14
21.02	21.54	20.73	19.94	19.37	20.54	21.02	22.86	19.97	19.63	20.74	21.52
21.47	22.20	20.78	20.51	19.49	20.74	21.77	23.50	20.52	19.97	20.94	22.08
21.77	22.53	20.95	20.54	19.69	21.00	22.17	23.86	20.55	20.52	21.14	22.53
22.17	22.86	21.06	20.71	20.51	21.15	22.53	23.95	20.73	20.55	21.52	22.53

2004 On-Peak

Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
25.93	26.45	23.51	22.53	22.53	30.51	37.48	37.48	23.63	22.53	23.62	25.93
27.25	29.11	23.76	22.86	22.84	30.89	37.48	37.48	23.89	23.50	24.18	27.25
30.51	30.89	23.89	23.50	23.15	34.81	37.48	37.48	24.03	23.63	24.70	30.51
30.89	32.49	24.03	23.63	23.53	37.48	37.48	37.48	24.18	23.82	25.48	30.89
34.81	35.84	24.18	23.82	23.73	37.48	37.48	37.48	24.72	23.89	25.96	34.81

2009 Off-Peak

Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
27.54	27.95	25.22	23.49	22.71	25.46	27.87	28.46	23.49	23.37	26.50	27.84
27.87	28.29	25.67	23.93	22.98	26.51	28.26	29.64	24.08	23.51	27.28	28.21
27.99	28.39	26.04	24.20	23.43	27.28	28.39	31.67	24.29	24.08	27.62	28.32
28.29	28.46	26.50	24.47	23.83	27.84	28.46	32.71	24.72	24.24	27.87	28.46
28.39	28.69	26.65	25.23	24.08	27.87	28.68	33.34	25.23	24.66	27.95	28.46

2009 On-Peak

Jan	*Feb*	*Mar*	*Apr*	*May*	*June*	*July*	*Aug*	*Sept*	*Oct*	*Nov*	*Dec*
44.12	44.12	29.87	28.46	28.46	44.12	44.12	44.12	32.05	28.70	33.45	44.12
44.12	44.12	31.67	28.88	28.70	44.12	44.12	44.12	33.13	29.56	37.35	44.12
44.12	44.12	32.71	29.56	29.46	44.12	44.12	44.12	33.45	30.46	44.12	44.12
44.12	44.12	33.37	30.35	29.64	44.12	44.12	44.12	37.35	32.05	44.12	44.12
44.12	44.12	37.35	32.05	30.97	44.12	44.12	44.12	44.12	33.13	44.12	44.12

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Capacity (MWs)		352	512	144	201	250	279	302	760	355	1,105	1,105
Capacity Factor	1999	85%	38%	79%	24%	20%	82%	77%	14%	85%	69%	69%
%	2000											
	2001											
	2002											
	2003											
	2004	86%	38%	72%	25%	19%	79%	72%	13%	86%	69%	69%
	2005											
	2006											
	2007											
	2008											
	2009	85%	38%	77%	24%	17%	82%	77%	12%	85%	69%	69%
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
Energy Output	1999	2,631,373	1,692,159	1,000,919	424,662	444,553	2,002,379	2,030,177	952,342	2,656,735	6,694,050	6,694,050
MWh	2000											
	2001											
	2002											
	2003											
	2004	2,640,237	1,692,999	908,435	442,282	415,855	1,937,820	1,907,462	898,527	2,665,423	6,718,378	6,718,378
	2005											
	2006											
	2007											
	2008											
	2009	2,632,305	1,693,000	975,157	419,364	363,360	2,003,840	2,043,784	818,282	2,657,446	6,696,260	6,696,260
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											

Exhibit WHH-4
Hieronymus
Testimony
1/16/97

Muddy Run *Muddy R*	**PeachBotto** *Peach B 2*	**PeachBotto** *Peach B 3*	**Salem 1** *Salem 1*	**Salem 2** *Salem 2*	**Schuylkill** *Schuylk 1*	**CT's** *CT's*	*Total*	*Average*	**Year**	
880	464	464	471	471	166	829	9,110			**Capacity (MWs)**
2%	69%	69%	69%	69%	20%	0%		49%	1999	**Capacity Factor**
									2000 **%**	
									2001	
									2002	
									2003	
4%	69%	69%	69%	69%	20%	0%		49%	2004	
									2005	
									2006	
									2007	
									2008	
6%	69%	69%	69%	69%	17%	0%		49%	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	
								Capacity		
180,258	2,810,839	2,810,839	2,853,576	2,853,576	297,321	17,062	39,046,869	49%	1999	**Energy Output**
							39,015,815	49%	2000 **MWh**	
							38,984,786	49%	2001	
							38,953,782	49%	2002	
							38,922,802	49%	2003	
274,766	2,821,055	2,821,055	2,863,947	2,863,947	287,739	13,546	38,891,847	49%	2004	
							38,928,944	49%	2005	
							38,966,077	49%	2006	
							39,003,246	49%	2007	
							39,040,449	49%	2008	
484,698	2,811,767	2,811,767	2,854,518	2,854,518	252,882	8,479	39,077,689	49%	2009	
							39,114,964	49%	2010	
							39,152,274	49%	2011	
							39,189,620	49%	2012	
							39,227,002	49%	2013	
							39,264,419	49%	2014	
							39,301,872	49%	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
***Average* Market Price of Energy $/MWh**	1999	17.8	20.9	20.1	21.5	21.1	20.1	20.3	20.8	17.9	19.7	19.9
	2000											
	2001											
	2002											
	2003											
	2004	22.0	27.1	26.2	28.0	26.8	25.6	26.0	26.7	22.3	25.4	25.3
	2005											
	2006											
	2007											
	2008											
	2009	29.2	33.9	32.3	34.4	32.6	31.6	31.7	33.5	29.5	31.8	31.3
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
***Energy* Revenues millions$**	1999	$47	$35	$20	$9	$9	$40	$41	$20	$48	$132	$133
	2000	$49	$37	$21	$10	$10	$42	$43	$21	$50	$139	$140
	2001	$51	$39	$21	$10	$10	$44	$44	$21	$52	$146	$147
	2002	$53	$41	$22	$11	$10	$46	$46	$22	$54	$154	$154
	2003	$56	$44	$23	$12	$11	$48	$48	$23	$57	$162	$162
	2004	$58	$46	$24	$12	$11	$50	$50	$24	$59	$171	$170
	2005	$61	$48	$25	$13	$11	$52	$52	$25	$63	$178	$177
	2006	$65	$50	$27	$13	$11	$55	$55	$25	$66	$186	$185
	2007	$69	$53	$28	$14	$12	$57	$58	$26	$70	$195	$193
	2008	$73	$55	$30	$14	$12	$60	$61	$27	$74	$203	$201
	2009	$77	$57	$32	$14	$12	$63	$65	$27	$78	$213	$210
	2010	$80	$60	$33	$15	$12	$66	$68	$29	$82	$223	$220
	2011	$84	$63	$35	$16	$13	$69	$71	$30	$86	$233	$230
	2012	$88	$66	$36	$17	$14	$73	$74	$31	$90	$244	$241
	2013	$92	$69	$38	$17	$14	$76	$78	$33	$94	$256	$252
	2014	$97	$72	$40	$18	$15	$80	$81	$35	$98	$268	$264
	2015	$101	$76	$42	$19	$16	$83	$85	$36	$103	$280	$276

**Exhibit WHH-4
Hieronymus
Testimony
1/16/97**

Muddy Run	PeachBotto	PeachBotto	Salem 1	Salem 2	Schuylkill	CT's				
Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	Total	Average	Year	
								($/MWh)		**Average**
25.7	19.7	19.9	19.7	20.0	21.1	26.3		19.7	1999	**Market**
									2000	**Price of**
									2001	**Energy**
									2002	**$/MWh**
									2003	
34.1	25.2	25.6	25.1	25.4	27.0	34.2		25.2	2004	
									2005	
									2006	
									2007	
									2008	
39.5	31.4	32.0	31.2	32.1	32.9	43.9		31.6	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	
								($/MWh)		**Energy**
$5	$56	$56	$56	$57	$6	$0	$771	19.7	1999	**Revenues**
$5	$58	$59	$59	$60	$7	$0	$808	20.7	2000	**millions$**
$6	$61	$62	$62	$63	$7	$0	$848	21.8	2001	
$7	$64	$65	$65	$66	$7	$0	$890	22.8	2002	
$8	$68	$69	$68	$69	$7	$0	$933	24.0	2003	
$9	$71	$72	$72	$73	$8	$0	$980	25.2	2004	
$11	$74	$76	$75	$76	$8	$0	$1,026	26.3	2005	
$12	$78	$79	$78	$80	$8	$0	$1,074	27.6	2006	
$14	$81	$82	$82	$84	$8	$0	$1,125	28.8	2007	
$17	$85	$86	$85	$88	$8	$0	$1,179	30.2	2008	
$19	$88	$90	$89	$92	$8	$0	$1,235	31.6	2009	
$20	$93	$94	$93	$96	$9	$0	$1,293	33.1	2010	
$21	$97	$99	$98	$101	$9	$0	$1,354	34.6	2011	
$22	$101	$103	$102	$105	$10	$0	$1,418	36.2	2012	
$23	$106	$108	$107	$110	$10	$0	$1,484	37.8	2013	
$24	$111	$113	$112	$115	$10	$0	$1,554	39.6	2014	
$25	$116	$118	$117	$121	$11	$0	$1,627	41.4	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Uplift Revenues	1999	$0	$0	$0	$3	$5	$0	$0	$12	$0	$0	$0
millions$	2000	$0	$0	$0	$3	$5	$0	$0	$13	$0	$0	$0
	2001	$0	$0	$0	$3	$6	$0	$0	$14	$0	$0	$0
	2002	$0	$0	$0	$3	$6	$0	$0	$15	$0	$0	$0
	2003	$0	$0	$0	$4	$6	$0	$0	$16	$0	$0	$0
	2004	$0	$0	$0	$4	$7	$0	$0	$17	$0	$0	$0
	2005	$0	$0	$0	$4	$7	$0	$0	$18	$0	$0	$0
	2006	$0	$0	$0	$5	$8	$0	$0	$19	$0	$0	$0
	2007	$0	$0	$0	$5	$8	$0	$0	$20	$0	$0	$0
	2008	$0	$0	$0	$5	$9	$0	$0	$21	$0	$0	$0
	2009	$0	$0	$0	$6	$9	$0	$0	$22	$0	$0	$0
	2010	$0	$0	$0	$6	$9	$0	$0	$22	$0	$0	$0
	2011	$0	$0	$0	$6	$10	$0	$0	$23	$0	$0	$0
	2012	$0	$0	$0	$6	$10	$0	$0	$23	$0	$0	$0
	2013	$0	$0	$0	$6	$10	$0	$0	$24	$0	$0	$0
	2014	$0	$0	$0	$6	$10	$0	$0	$25	$0	$0	$0
	2015	$0	$0	$0	$6	$11	$0	$0	$25	$0	$0	$0
Energy Plus Uplift Revenues	1999	$47	$35	$20	$12	$14	$40	$41	$32	$48	$132	$133
millions$	2000	$49	$37	$21	$13	$15	$42	$43	$33	$50	$139	$140
	2001	$51	$39	$21	$14	$16	$44	$44	$35	$52	$146	$147
	2002	$53	$41	$22	$14	$16	$46	$46	$37	$54	$154	$154
	2003	$56	$44	$23	$15	$17	$48	$48	$39	$57	$162	$162
	2004	$58	$46	$24	$16	$18	$50	$50	$41	$59	$171	$170
	2005	$61	$48	$25	$17	$19	$52	$52	$42	$63	$178	$177
	2006	$65	$50	$27	$18	$19	$55	$55	$44	$66	$186	$185
	2007	$69	$53	$28	$18	$20	$57	$58	$46	$70	$195	$193
	2008	$73	$55	$30	$19	$20	$60	$61	$47	$74	$203	$201
	2009	$77	$57	$32	$20	$21	$63	$65	$49	$78	$213	$210
	2010	$80	$60	$33	$21	$22	$66	$68	$51	$82	$223	$220
	2011	$84	$63	$35	$22	$23	$69	$71	$53	$86	$233	$230
	2012	$88	$66	$36	$23	$24	$73	$74	$55	$90	$244	$241
	2013	$92	$69	$38	$23	$24	$76	$78	$57	$94	$256	$252
	2014	$97	$72	$40	$24	$25	$80	$81	$59	$98	$268	$264
	2015	$101	$76	$42	$25	$26	$83	$85	$61	$103	$280	$276

Exhibit WHH-4
Hieronymus
Testimony
1/16/97

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average	Year	
								($/MWh)		**Uplift**
$0	$0	$0	$0	$0	$3	$4	$26	0.7	1999	**Revenues**
$0	$0	$0	$0	$0	$3	$4	$28	0.7	2000	**millions$**
$0	$0	$0	$0	$0	$4	$4	$30	0.8	2001	
$0	$0	$0	$0	$0	$4	$4	$32	0.8	2002	
$0	$0	$0	$0	$0	$4	$4	$34	0.9	2003	
$0	$0	$0	$0	$0	$5	$4	$36	0.9	2004	
$0	$0	$0	$0	$0	$5	$4	$38	1.0	2005	
$0	$0	$0	$0	$0	$5	$4	$40	1.0	2006	
$0	$0	$0	$0	$0	$5	$4	$42	1.1	2007	
$0	$0	$0	$0	$0	$6	$4	$44	1.1	2008	
$0	$0	$0	$0	$0	$6	$3	$46	1.2	2009	
$0	$0	$0	$0	$0	$6	$4	$47	1.2	2010	
$0	$0	$0	$0	$0	$6	$4	$49	1.2	2011	
$0	$0	$0	$0	$0	$7	$4	$50	1.3	2012	
$0	$0	$0	$0	$0	$7	$4	$51	1.3	2013	
$0	$0	$0	$0	$0	$7	$4	$52	1.3	2014	
$0	$0	$0	$0	$0	$7	$4	$54	1.4	2015	
								($/MWh)		**Energy**
$5	$56	$56	$56	$57	$9	$4	$797	20.4	1999	**Plus**
$5	$58	$59	$59	$60	$10	$4	$836	21.4	2000	**Uplift**
$6	$61	$62	$62	$63	$10	$4	$878	22.5	2001	**Revenues**
$7	$64	$65	$65	$66	$11	$4	$922	23.7	2002	**millions$**
$8	$68	$69	$68	$69	$12	$5	$967	24.9	2003	
$9	$71	$72	$72	$73	$12	$5	$1,016	26.1	2004	
$11	$74	$76	$75	$76	$13	$4	$1,064	27.3	2005	
$12	$78	$79	$78	$80	$13	$4	$1,114	28.6	2006	
$14	$81	$82	$82	$84	$14	$4	$1,167	29.9	2007	
$17	$85	$86	$85	$88	$14	$4	$1,223	31.3	2008	
$19	$88	$90	$89	$92	$14	$4	$1,281	32.8	2009	
$20	$93	$94	$93	$96	$15	$4	$1,341	34.3	2010	
$21	$97	$99	$98	$101	$16	$4	$1,403	35.8	2011	
$22	$101	$103	$102	$105	$16	$4	$1,467	37.4	2012	
$23	$106	$108	$107	$110	$17	$4	$1,535	39.1	2013	
$24	$111	$113	$112	$115	$17	$4	$1,606	40.9	2014	
$25	$116	$119	$117	$121	$18	$4	$1,681	42.8	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Capacity Price	1999	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
$/KW	2000	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7
	2001	50.9	50.9	50.9	50.9	50.9	50.9	50.9	50.9	50.9	50.9	50.9
	2002	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2
	2003	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5	53.5
	2004	54.8	54.8	54.8	54.8	54.8	54.8	54.8	54.8	54.8	54.8	54.8
	2005	56.2	56.2	56.2	56.2	56.2	56.2	56.2	56.2	56.2	56.2	56.2
	2006	57.6	57.6	57.6	57.6	57.6	57.6	57.6	57.6	57.6	57.6	57.6
	2007	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
	2008	60.5	60.5	60.5	60.5	60.5	60.5	60.5	60.5	60.5	60.5	60.5
	2009	62.0	62.0	62.0	62.0	62.0	62.0	62.0	62.0	62.0	62.0	62.0
	2010	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6
	2011	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2
	2012	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8
	2013	68.5	68.5	68.5	68.5	68.5	68.5	68.5	68.5	68.5	68.5	68.5
	2014	70.2	70.2	70.2	70.2	70.2	70.2	70.2	70.2	70.2	70.2	70.2
	2015	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9
Capacity Revenues	1999	$6	$8	$2	$3	$4	$5	$5	$12	$6	$18	$18
millions$	2000	$10	$15	$4	$6	$7	$8	$9	$22	$10	$32	$32
	2001	$18	$26	$7	$10	$13	$14	$15	$39	$18	$56	$56
	2002	$18	$27	$8	$10	$13	$15	$16	$40	$19	$58	$58
	2003	$19	$27	$8	$11	$13	$15	$16	$41	$19	$59	$59
	2004	$19	$28	$8	$11	$14	$15	$17	$42	$19	$61	$61
	2005	$20	$29	$8	$11	$14	$16	$17	$43	$20	$62	$62
	2006	$20	$29	$8	$12	$14	$16	$17	$44	$20	$64	$64
	2007	$21	$30	$9	$12	$15	$16	$18	$45	$21	$65	$65
	2008	$21	$31	$9	$12	$15	$17	$18	$46	$22	$67	$67
	2009	$22	$32	$9	$12	$16	$17	$19	$47	$22	$69	$69
	2010	$22	$33	$9	$13	$16	$18	$19	$48	$23	$70	$70
	2011	$23	$33	$9	$13	$16	$18	$20	$50	$23	$72	$72
	2012	$24	$34	$10	$13	$17	$19	$20	$51	$24	$74	$74
	2013	$24	$35	$10	$14	$17	$19	$21	$52	$24	$76	$76
	2014	$25	$36	$10	$14	$18	$20	$21	$53	$25	$78	$78
	2015	$25	$37	$10	$14	$18	$20	$22	$55	$26	$79	$79

Exhibit WHH-4
Hieronymus
Testimony
1/16/97

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average	Year	
								($/KW)		Capacity
16.2	16.2	16.2	16.2	16.2	16.2	16.2		16.2	1999	Price
28.7	28.7	28.7	28.7	28.7	28.7	28.7		28.7	2000	$/KW
50.9	50.9	50.9	50.9	50.9	50.9	50.9		50.9	2001	
52.2	52.2	52.2	52.2	52.2	52.2	52.2		52.2	2002	
53.5	53.5	53.5	53.5	53.5	53.5	53.5		53.5	2003	
54.8	54.8	54.8	54.8	54.8	54.8	54.8		54.8	2004	
56.2	56.2	56.2	56.2	56.2	56.2	56.2		56.2	2005	
57.6	57.6	57.6	57.6	57.6	57.6	57.6		57.6	2006	
59.0	59.0	59.0	59.0	59.0	59.0	59.0		59.0	2007	
60.5	60.5	60.5	60.5	60.5	60.5	60.5		60.5	2008	
62.0	62.0	62.0	62.0	62.0	62.0	62.0		62.0	2009	
63.6	63.6	63.6	63.6	63.6	63.6	63.6		63.6	2010	
65.2	65.2	65.2	65.2	65.2	65.2	65.2		65.2	2011	
66.8	66.8	66.8	66.8	66.8	66.8	66.8		66.8	2012	
68.5	68.5	68.5	68.5	68.5	68.5	68.5		68.5	2013	
70.2	70.2	70.2	70.2	70.2	70.2	70.2		70.2	2014	
71.9	71.9	71.9	71.9	71.9	71.9	71.9		71.9	2015	
								($/MWh)		Capacity
$14	$7	$7	$8	$8	$3	$13	$147	3.8	1999	Revenues
$25	$13	$13	$14	$14	$5	$24	$261	6.7	2000	millions$
$45	$24	$24	$24	$24	$8	$42	$464	11.9	2001	
$46	$24	$24	$25	$25	$9	$43	$475	12.2	2002	
$47	$25	$25	$25	$25	$9	$44	$487	12.5	2003	
$48	$25	$25	$26	$26	$9	$45	$499	12.8	2004	
$49	$26	$26	$26	$26	$9	$47	$512	13.1	2005	
$51	$27	$27	$27	$27	$10	$48	$525	13.5	2006	
$52	$27	$27	$28	$28	$10	$49	$538	13.8	2007	
$53	$28	$28	$29	$29	$10	$50	$551	14.1	2008	
$55	$29	$29	$29	$29	$10	$51	$565	14.5	2009	
$56	$30	$30	$30	$30	$11	$53	$579	14.8	2010	
$57	$30	$30	$31	$31	$11	$54	$594	15.2	2011	
$59	$31	$31	$31	$31	$11	$55	$609	15.5	2012	
$60	$32	$32	$32	$32	$11	$57	$624	15.9	2013	
$62	$33	$33	$33	$33	$12	$58	$639	16.3	2014	
$63	$33	$33	$34	$34	$12	$60	$655	16.7	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Energy												
Plus	1999	$53	$44	$22	$15	$18	$45	$46	$44	$53	$150	$151
Uplift	2000	$59	$52	$25	$19	$22	$50	$51	$55	$60	$170	$171
Plus	2001	$69	$65	$29	$24	$28	$58	$60	$74	$70	$202	$203
Capacity	2002	$72	$68	$30	$25	$29	$60	$62	$76	$73	$211	$212
Revenues	2003	$74	$71	$31	$26	$31	$63	$64	$79	$76	$221	$221
millions$	2004	$77	$74	$32	$27	$32	$65	$66	$82	$79	$231	$230
	2005	$81	$77	$33	$28	$33	$68	$69	$85	$83	$240	$239
	2006	$85	$80	$35	$29	$34	$71	$73	$88	$87	$250	$248
	2007	$89	$83	$37	$30	$35	$74	$76	$90	$91	$260	$258
	2008	$94	$86	$39	$31	$36	$77	$80	$93	$96	$270	$268
	2009	$99	$89	$40	$32	$37	$81	$83	$96	$100	$281	$278
	2010	$103	$93	$42	$34	$38	$84	$87	$99	$105	$293	$290
	2011	$107	$96	$44	$35	$39	$88	$91	$102	$109	$305	$302
	2012	$112	$100	$46	$36	$40	$91	$94	$106	$114	$318	$315
	2013	$116	$104	$48	$37	$42	$95	$98	$109	$118	$331	$328
	2014	$121	$108	$50	$39	$43	$99	$103	$113	$123	$345	$342
	2015	$127	$112	$52	$40	$44	$104	$107	$116	$129	$360	$356

Exhibit WHH-4
Hieronymus
Testimony
1/16/97

Muddy Run	PeachBotto	PeachBotto	Salem 1	Salem 2	Schuylkill	CT's				
Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	Total	Average	Year	
								($/MWh)		Energy
$19	$63	$63	$64	$65	$12	$18	$944	24.2	1999	Plus
$31	$72	$72	$72	$73	$15	$28	$1,098	28.1	2000	Uplift
$51	$85	$86	$86	$87	$19	$47	$1,342	34.4	2001	Plus
$53	$89	$89	$90	$91	$20	$48	$1,397	35.9	2002	Capacity
$55	$92	$94	$94	$95	$21	$49	$1,455	37.4	2003	Revenues
$58	$96	$98	$98	$99	$21	$50	$1,515	39.0	2004	millions$
$60	$100	$102	$101	$103	$22	$51	$1,576	40.5	2005	
$63	$104	$106	$105	$107	$23	$52	$1,639	42.1	2006	
$66	$108	$110	$109	$111	$23	$53	$1,705	43.7	2007	
$70	$113	$114	$114	$116	$24	$54	$1,774	45.4	2008	
$74	$117	$119	$118	$121	$25	$55	$1,846	47.3	2009	
$76	$122	$124	$123	$126	$26	$57	$1,920	49.1	2010	
$78	$127	$129	$128	$131	$26	$58	$1,996	51.0	2011	
$81	$132	$134	$134	$137	$27	$60	$2,076	53.0	2012	
$83	$138	$140	$139	$142	$28	$61	$2,159	55.0	2013	
$86	$144	$146	$145	$148	$29	$63	$2,246	57.2	2014	
$89	$150	$152	$151	$155	$30	$64	$2,336	59.4	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Average												
Fuel	1999	11.1	0.0	14.7	27.0	29.7	14.0	14.5	31.1	10.6	4.5	4.5
Cost	2000											
$/MWh	2001											
	2002											
	2003											
	2004	12.7	0.0	19.8	35.3	41.1	18.9	19.3	43.0	15.8	4.6	4.6
	2005											
	2006											
	2007											
	2008											
	2009	14.3	0.0	23.5	45.9	55.3	22.4	23.0	57.5	19.5	5.4	5.4
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
Fuel												
Cost	1999	$29	$0	$15	$11	$13	$28	$29	$30	$28	$30	$30
million$	2000	$30	$0	$15	$12	$14	$30	$31	$31	$31	$30	$30
	2001	$31	$0	$16	$13	$15	$31	$32	$33	$33	$30	$30
	2002	$32	$0	$17	$14	$15	$33	$34	$35	$36	$30	$30
	2003	$33	$0	$17	$15	$16	$35	$35	$37	$39	$30	$30
	2004	$33	$0	$18	$16	$17	$37	$37	$39	$42	$31	$31
	2005	$34	$0	$19	$16	$18	$38	$39	$40	$44	$31	$31
	2006	$35	$0	$20	$17	$18	$40	$41	$42	$46	$33	$33
	2007	$36	$0	$21	$18	$19	$41	$43	$43	$48	$34	$34
	2008	$37	$0	$22	$18	$19	$43	$45	$45	$50	$35	$35
	2009	$38	$0	$23	$19	$20	$45	$47	$47	$52	$36	$36
	2010	$39	$0	$24	$20	$21	$46	$48	$49	$53	$38	$38
	2011	$40	$0	$24	$21	$22	$47	$50	$52	$55	$39	$39
	2012	$41	$0	$25	$22	$23	$49	$51	$55	$56	$41	$41
	2013	$42	$0	$26	$23	$25	$50	$52	$57	$58	$42	$42
	2014	$43	$0	$26	$24	$26	$51	$54	$60	$59	$44	$44
	2015	$44	$0	$27	$25	$27	$53	$55	$63	$61	$45	$45

Exhibit WHH-4
Hieronymus
Testimony
1/16/97

Muddy Run Muddy R	**PeachBotto** Peach B 2	**PeachBotto** Peach B 3	**Salem 1** Salem 1	**Salem 2** Salem 2	**Schuylkill** Schuylk 1	**CT's** CT's	Total	Average	**Year**	
								($/MWh)		**Average**
24.7	5.8	5.8	5.8	5.8	29.2	252.5		8.4	1999	***Fuel***
									2000	**Cost**
									2001	**$/MWh**
									2002	
									2003	
31.5	5.8	5.8	5.8	5.8	40.6	336.0		10.1	2004	
									2005	
									2006	
									2007	
									2008	
37.0	6.8	6.8	6.8	6.8	54.4	449.6		12.2	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	
								($/MWh)		**Fuel**
$4	$16	$16	$17	$17	$9	$4	$327	8.4	1999	**Cost**
$5	$16	$16	$16	$16	$9	$4	$336	8.6	2000	**million$**
$6	$16	$16	$16	$16	$10	$4	$347	8.9	2001	
$7	$16	$16	$16	$16	$10	$4	$361	9.3	2002	
$8	$16	$16	$16	$16	$11	$5	$375	9.6	2003	
$9	$16	$16	$17	$17	$12	$5	$391	10.1	2004	
$10	$17	$17	$17	$17	$12	$4	$405	10.4	2005	
$12	$17	$17	$18	$18	$12	$4	$422	10.8	2006	
$13	$18	$18	$18	$18	$13	$4	$439	11.3	2007	
$15	$19	$19	$19	$19	$13	$4	$458	11.7	2008	
$18	$19	$19	$20	$20	$14	$4	$476	12.2	2009	
$19	$20	$20	$20	$20	$14	$4	$494	12.6	2010	
$20	$21	$21	$21	$21	$15	$4	$511	13.1	2011	
$21	$21	$21	$22	$22	$16	$4	$530	13.5	2012	
$22	$22	$22	$23	$23	$17	$5	$548	14.0	2013	
$23	$23	$23	$23	$23	$18	$5	$568	14.5	2014	
$24	$24	$24	$24	$24	$19	$5	$588	15.0	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Revenues												
Minus	1999	$23	$44	$8	$4	$5	$17	$17	$14	$25	$120	$121
Fuel	2000	$29	$52	$10	$6	$8	$20	$21	$24	$29	$141	$142
Costs	*2001*	*$38*	*$65*	*$13*	*$11*	*$14*	*$27*	*$28*	*$41*	*$37*	*$173*	*$173*
million$	2002	$40	$68	$13	$11	$14	$27	$28	$42	$37	$181	$181
	2003	$42	$71	$13	$11	$14	$28	$29	$43	$37	$191	$190
	2004	$44	$74	$14	$12	$15	$28	$29	$44	$37	$200	$199
	2005	$47	$77	$14	$12	$15	$30	$31	$45	$39	$209	$208
	2006	$50	$80	$15	$12	$15	$31	$32	$46	$41	$217	$216
	2007	$54	$83	$16	$13	$16	$33	$33	$47	$43	$226	$224
	2008	$57	$86	$17	$13	$16	$34	$35	$48	$46	$235	$233
	2009	$61	$89	$18	$13	$16	$36	$36	$49	$49	$245	$242
	2010	$64	$93	$19	$13	$17	$38	$39	$50	$51	$255	$252
	2011	$68	$96	$20	$14	$17	$40	$41	$51	$54	$266	$263
	2012	$71	$100	$21	$14	$17	$43	$44	$51	$58	$277	$274
	2013	$75	$104	$22	$14	$17	$45	$46	$52	$61	$289	$286
	2014	$78	$108	$24	$14	$17	$48	$49	$52	$64	$302	$298
	2015	$82	$112	$25	$15	$17	$51	$52	$53	$68	$315	$311

Exhibit WHH-4
Hieronymus
Testimony
1/16/97

Revenues Minus Fuel Costs million$

Muddy Run Muddy R	**PeachBotto** Peach B 2	**PeachBotto** Peach B 3	**Salem 1** Salem 1	**Salem 2** Salem 2	**Schuylkill** Schuylk 1	**CT's** CT's	Total	Average (**$/MWh**)	**Year**
$14	$47	$47	$47	$48	$3	$13	$617	15.8	1999
$25	$55	$56	$56	$57	$5	$24	$761	19.5	2000
$45	$69	$70	$70	$71	$9	$42	$994	25.5	2001
$46	$72	$73	$73	$74	$9	$43	$1,036	26.6	2002
$48	$76	$77	$77	$78	$10	$44	$1,079	27.7	2003
$49	$80	$81	$81	$82	$10	$45	$1,124	28.9	2004
$50	$83	$85	$84	$86	$10	$47	$1,171	30.1	2005
$52	$87	$88	$88	$89	$10	$48	$1,217	31.2	2006
$53	$90	$92	$91	$93	$10	$49	$1,266	32.4	2007
$54	$94	$96	$95	$97	$11	$50	$1,316	33.7	2008
$56	$98	$100	$99	$101	$11	$51	$1,370	35.1	2009
$57	$102	$104	$103	$106	$11	$53	$1,426	36.4	2010
$59	$107	$108	$107	$110	$11	$54	$1,485	37.9	2011
$60	$111	$113	$112	$115	$11	$55	$1,546	39.5	2012
$62	$116	$118	$117	$120	$11	$56	$1,611	41.1	2013
$63	$121	$123	$122	$125	$11	$58	$1,677	42.7	2014
$65	$126	$128	$127	$131	$11	$59	$1,748	44.5	2015

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Variable												
O&M Cost	1999	2.2	0.0	2.2	1.3	2.1	2.2	2.2	2.1	2.2	0.6	0.6
$/MWh	2000											
	2001											
	2002											
	2003											
	2004	2.4	0.0	2.4	1.5	2.3	2.4	2.4	2.3	2.4	0.7	0.7
	2005											
	2006											
	2007											
	2008											
	2009	2.8	0.0	2.8	1.7	2.6	2.8	2.8	2.6	2.8	0.8	0.8
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
Variable												
O&M Cost	1999	$6	$0	$2	$1	$1	$4	$4	$2	$6	$4	$4
million$	2000	$6	$0	$2	$1	$1	$4	$4	$2	$6	$4	$4
	2001	$6	$0	$2	$1	$1	$4	$4	$2	$6	$5	$5
	2002	$6	$0	$2	$1	$1	$5	$5	$2	$6	$5	$5
	2003	$6	$0	$2	$1	$1	$5	$5	$2	$6	$5	$5
	2004	$6	$0	$2	$1	$1	$5	$5	$2	$6	$5	$5
	2005	$7	$0	$2	$1	$1	$5	$5	$2	$7	$5	$5
	2006	$7	$0	$2	$1	$1	$5	$5	$2	$7	$5	$5
	2007	$7	$0	$2	$1	$1	$5	$5	$2	$7	$5	$5
	2008	$7	$0	$3	$1	$1	$5	$5	$2	$7	$5	$5
	2009	$7	$0	$3	$1	$1	$6	$6	$2	$7	$6	$6
	2010	$7	$0	$3	$1	$1	$6	$6	$2	$8	$6	$6
	2011	$8	$0	$3	$1	$1	$6	$6	$2	$8	$6	$6
	2012	$8	$0	$3	$1	$1	$6	$6	$2	$8	$6	$6
	2013	$8	$0	$3	$1	$1	$6	$6	$2	$8	$6	$6
	2014	$8	$0	$3	$1	$1	$6	$6	$2	$8	$6	$6
	2015	$8	$0	$3	$1	$1	$6	$7	$3	$8	$6	$6

Exhibit WHH-4
Hieronymus
Testimony
1/16/97

Variable O&M Cost $/MWh

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average ($/MWh)	Year
0.0	0.6	0.6	0.6	0.6	2.1	1.6		1.1	1999
									2000
									2001
									2002
									2003
0.0	0.7	0.7	0.7	0.7	2.3	1.8		1.2	2004
									2005
									2006
									2007
									2008
0.0	0.8	0.8	0.8	0.8	2.6	2.1		1.4	2009
									2010
									2011
									2012
									2013
									2014
									2015

Variable O&M Cost million$

Muddy Run	PeachBotto	PeachBotto	Salem 1	Salem 2	Schuylkill	CT's	Total	Average ($/MWh)	Year
$0	$2	$2	$2	$2	$1	$0	$42	1.1	1999
$0	$2	$2	$2	$2	$1	$0	$43	1.1	2000
$0	$2	$2	$2	$2	$1	$0	$44	1.1	2001
$0	$2	$2	$2	$2	$1	$0	$45	1.2	2002
$0	$2	$2	$2	$2	$1	$0	$46	1.2	2003
$0	$2	$2	$2	$2	$1	$0	$47	1.2	2004
$0	$2	$2	$2	$2	$1	$0	$48	1.2	2005
$0	$2	$2	$2	$2	$1	$0	$50	1.3	2006
$0	$2	$2	$2	$2	$1	$0	$51	1.3	2007
$0	$2	$2	$2	$2	$1	$0	$52	1.3	2008
$0	$2	$2	$2	$2	$1	$0	$53	1.4	2009
$0	$2	$2	$2	$2	$1	$0	$55	1.4	2010
$0	$2	$2	$2	$2	$1	$0	$56	1.4	2011
$0	$3	$3	$3	$3	$1	$0	$58	1.5	2012
$0	$3	$3	$3	$3	$1	$0	$59	1.5	2013
$0	$3	$3	$3	$3	$1	$0	$60	1.5	2014
$0	$3	$3	$3	$3	$1	$0	$62	1.6	2015

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Total Incremental Costs million$	1999	$35	$0	$17	$12	$14	$32	$34	$32	$34	$34	$34
	2000	$36	$0	$18	$13	$15	$34	$35	$33	$36	$34	$34
	2001	$37	$0	$18	$14	$16	$36	$37	$35	$39	$34	$34
	2002	$38	$0	$19	$14	$16	$38	$38	$37	$42	$35	$35
	2003	$39	$0	$19	$15	$17	$39	$40	$39	$45	$35	$35
	2004	$40	$0	$20	$16	$18	$41	$42	$41	$49	$36	$36
	2005	$41	$0	$21	$17	$19	$43	$44	$42	$51	$36	$36
	2006	$42	$0	$22	$18	$19	$45	$46	$44	$53	$38	$38
	2007	$43	$0	$23	$18	$20	$47	$48	$46	$55	$39	$39
	2008	$44	$0	$24	$19	$20	$48	$50	$47	$57	$41	$41
	2009	$45	$0	$26	$20	$21	$50	$53	$49	$59	$42	$42
	2010	$46	$0	$26	$21	$22	$52	$54	$52	$61	$44	$44
	2011	$47	$0	$27	$22	$23	$53	$55	$54	$62	$45	$45
	2012	$48	$0	$28	$23	$24	$55	$57	$57	$64	$47	$47
	2013	$50	$0	$29	$24	$26	$56	$59	$60	$66	$48	$48
	2014	$51	$0	$29	$25	$27	$58	$60	$63	$67	$50	$50
	2015	$52	$0	$30	$26	$28	$59	$62	$66	$69	$51	$51
Margin million$	1999	$18	$44	$6	$3	$4	$12	$12	$12	$19	$115	$117
	2000	$23	$52	$7	$6	$7	$16	$16	$22	$24	$136	$137
	2001	$32	$65	$11	$10	$13	$22	$23	$39	$31	$168	$169
	2002	$34	$68	$11	$10	$13	$23	$24	$40	$31	$177	$177
	2003	$36	$71	$11	$11	$13	$23	$24	$41	$31	$186	$185
	2004	$37	$74	$11	$11	$14	$24	$25	$42	$30	$195	$194
	2005	$40	$77	$12	$11	$14	$25	$26	$43	$32	$204	$203
	2006	$43	$80	$13	$12	$14	$26	$27	$44	$34	$212	$210
	2007	$47	$83	$13	$12	$15	$27	$28	$45	$36	$221	$219
	2008	$50	$86	$14	$12	$15	$29	$29	$46	$39	$230	$227
	2009	$54	$89	$15	$12	$16	$30	$31	$47	$41	$239	$236
	2010	$57	$93	$16	$13	$16	$32	$33	$48	$44	$249	$246
	2011	$60	$96	$17	$13	$16	$34	$35	$48	$47	$260	$257
	2012	$63	$100	$18	$13	$16	$37	$37	$49	$50	$271	$268
	2013	$67	$104	$19	$13	$16	$39	$40	$49	$53	$283	$280
	2014	$70	$108	$21	$13	$16	$42	$43	$50	$56	$295	$292
	2015	$74	$112	$22	$14	$16	$44	$45	$50	$60	$308	$304

Exhibit WHH-4
Hieronymus
Testimony
1/16/97

Total Incremental Costs million$

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average ($/MWh)	Year
$4	$18	$18	$19	$19	$9	$4	$369	9.5	1999
$5	$18	$18	$18	$18	$10	$4	$380	9.7	2000
$6	$18	$18	$18	$18	$10	$4	$392	10.0	2001
$7	$18	$18	$18	$18	$11	$4	$406	10.4	2002
$8	$18	$18	$18	$18	$12	$5	$421	10.8	2003
$9	$19	$19	$19	$19	$12	$5	$439	11.3	2004
$10	$19	$19	$19	$19	$13	$4	$453	11.6	2005
$12	$20	$20	$20	$20	$13	$4	$471	12.1	2006
$13	$20	$20	$21	$21	$14	$4	$490	12.6	2007
$15	$21	$21	$21	$21	$14	$4	$510	13.1	2008
$18	$22	$22	$22	$22	$14	$4	$530	13.6	2009
$19	$22	$22	$23	$23	$15	$4	$549	14.0	2010
$20	$23	$23	$23	$23	$16	$4	$567	14.5	2011
$21	$24	$24	$24	$24	$17	$4	$587	15.0	2012
$22	$25	$25	$25	$25	$18	$5	$607	15.5	2013
$23	$26	$26	$26	$26	$18	$5	$629	16.0	2014
$24	$26	$26	$27	$27	$19	$5	$650	16.5	2015

Margin million$

Muddy Run	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	Total	Average ($/MWh)	Year
$14	$45	$45	$45	$46	$3	$13	$575	14.7	1999
$25	$54	$54	$54	$55	$5	$24	$718	18.4	2000
$45	$67	$68	$68	$69	$8	$42	$950	24.4	2001
$46	$71	$71	$71	$72	$9	$43	$991	25.4	2002
$48	$74	$75	$75	$76	$9	$44	$1,033	26.5	2003
$49	$78	$79	$79	$80	$9	$45	$1,077	27.7	2004
$50	$81	$83	$82	$83	$9	$47	$1,122	28.8	2005
$52	$85	$86	$86	$87	$10	$48	$1,167	30.0	2006
$53	$88	$90	$89	$91	$10	$49	$1,215	31.1	2007
$54	$92	$93	$93	$95	$10	$50	$1,264	32.4	2008
$56	$96	$97	$96	$99	$10	$51	$1,317	33.7	2009
$57	$100	$101	$100	$103	$10	$53	$1,371	35.0	2010
$59	$104	$106	$105	$108	$10	$54	$1,429	36.5	2011
$60	$109	$110	$109	$112	$11	$55	$1,489	38.0	2012
$62	$113	$115	$114	$117	$11	$56	$1,552	39.6	2013
$63	$118	$120	$119	$122	$11	$58	$1,617	41.2	2014
$65	$123	$125	$124	$128	$11	$59	$1,686	42.9	2015

Overview of the Multi-Area Production Simulation Program (MAPS)[1]

MAPS is a highly-detailed model that calculates hour-by-hour production costs while recognizing the constraints on generation dispatch imposed by the transmission system. MAPS performs a transmission-constrained production simulation, which uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This makes it possible to capture the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints.

Because of its detailed electrical representation of the transmission system, MAPS can be used to study issues that cannot be adequately modeled with conventional production costing software. These issues include:

- **Locational Spot Pricing** - MAPS calculates the hourly spot price ($/MWh) at each bus modeled -- which is the cost of supplying an addition MW of load at the bus. The difference in spot prices at two buses is the short-run *marginal wheeling cost between these buses. Hence, MAPS can be used to* characterize the value of energy at different locations and the implied short-run value of transmission.
- **Transmission Bottlenecks** - MAPS can determine which transmission lines and interfaces in the system are bottlenecks and how many hours during the year they are limiting. MAPS can then be used to assess, from an economic point of view, the relative value of generation on each side of the interface and the feasibility of various methods, such as transmission line upgrades or the installation of phase-angle regulators, for alleviating the bottlenecks.
- **Power Wheeling** - MAPS can determine which transmission lines are actually carrying wheeled power, including lines that may not be part of the contract path. MAPS can also approximate the change in system losses due to a wheeling transaction.
- **Transmission Access** - The hourly spot price at each bus defines a key component of the total avoided cost that is used in formulating contracts for transmission access by non-utility generators and independent power producers.

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[1] This overview of MAPS has been prepared by PHB. It based on the similarly titled GE publication. The contents of the GE publication have been reorganized and the text has been edited.

- ***Loop Flow or Uncompensated Wheeling*** - *The detailed transmission* modeling and cost reconstruction algorithms in MAPS combine to identify which companies are contributing to the flow on a given transmission line and to defining the production cost impact of that loading.

The following sections provide more details on the specific modeling capability of MAPS. Production costing features are outlined first, followed by a discussion of how transmission system characteristics are incorporated into MAPS.

PRODUCTION COSTING

MAPS models the system chronologically on an hourly basis, dispatching the generation to serve the load for all of the hours in the year. In doing so, MAPS is able to capture the diversity that may exist throughout the system, and accurately model resources such as *energy-storage and demand-side management.*

The hourly load data is input to the program in EEI (Edison Electric Institute) format for each load forecast area. These hourly load profiles are then adjusted to meet the peak and energy forecasts input to the model. In order to accurately calculate the electrical flows on the transmission system, MAPS requires information on the hourly loads at each bus in the system. This is specified by assigning one, or a combination of several, of the hourly load profiles to each load bus.

In addition to studying all of the hours in the year, MAPS can be directed to study all of the days in the year on a bi-hourly basis, or a typical week per month on an hourly or bi-hourly basis. With all of these modeling options, MAPS simulates the loads in chronological order and does not sort them into load duration curves.

Produce hourly, marginal cost information

MAPS computes hourly spot prices at individual buses. The bus spot price is the cost of supplying an addition MW of load at the bus and includes the cost of generating the energy, the cost of the incremental transmission losses, and any costs associated with re-dispatching the generation if this additional increment of load caused overloads on the transmission system. The difference in spot prices at two buses is the short-run marginal wheeling cost between these buses.

MAPS can also develop marginal costs on a company and pool basis. There are two types of marginal cost calculations in MAPS: incremental and delta. Incremental marginal costs are calculated from a single dispatch and are equal to the cost of the last increment of power generated. Delta costs are calculated from two dispatches and equal the average cost of the change in energy dispatched. The hourly marginal costs can be summarized for on-, mid-, and off-peak periods by month, season, and year.

Thermal unit characteristics

Listed below are the thermal unit characteristics modeled in MAPS. Essentially all of the unit characteristics input to MAPS can be changed on a weekly, monthly, or annual basis.

a. Each unit can have up to seven loading segments (power points).

b. Generating units can bum a blend of up to three fuel types in addition to the start-up fuel. The percentage of each fuel burned can vary by unit power point.

c. In the unit commitment process, MAPS models the minimum down-times on thermal units. Units can also be identified as must-run with the user specifying that the entire unit is must-run, or only the minimum portion, with the remainder of the unit committed on an economic basis as needed.

d. MAPS models summer and winter unit capacities. The user defines the summer and winter seasons.

e. MAPS calculates start-up costs as a function of the number of hours that the unit has been off-line.

f. MAPS allows the user to specify the portion of each thermal unit that can be counted towards meeting the load plus spinning reserve requirements, and the portion that can be considered as quick-start capacity. A spinning reserve credit can also be taken for unused pondage hydro and energy-storage generating capacity.

g. Full and partial forced outage information is specified to MAPS in terms of forced outage rates.

h. MAPS models fixed O&M in $/kW/yr. and variable O&M in $/MWh and $/fired hour. The user controls whether the variable O&M is included in determining the order for unit commitment and dispatch.

i. Maintenance can be specified on a daily basis for any number of maintenance periods during the year. The user can also identify units as being unavailable for specific hours during the day.

j. MAPS allows all types of generating units (thermal, pondage, and energy storage) to be owned by more than one company in a multi-utility simulation. The output and cost of these units are allocated to the owning companies based on the user-specified percentages.

Perform centralized and local area commitment and dispatch on an hour-by-hour basis

MAPS models the system chronologically on an hourly basis, dispatching the generation to serve the load for all of the hours in the year. Several options are available when doing the thermal unit commitment. With the first option, separate unit commitments are used for the system and company own-load dispatches (see the next section). The commitment is first done for the entire system, taking into account the continuous rating of the units, the area loads, and the transfer limitations between the areas. Additional generation is then committed as needed to meet the spinning reserve requirements of each area and the system as a whole. Individual company commitments are then performed subject to the company spinning reserve requirements.

The next option begins with the system commitment to meet load. Additional units are then committed to ensure that each company has sufficient capacity committed to meet its load. Additional generation is then committed to meet the spinning reserve requirements of the companies, areas, and system. This commitment is then used for the system and company own-load dispatches.

The final option uses the sum of the company commitments for the system commitment, with additional units being committed as needed to meet the system spinning reserve requirements. This commitment is then used for both dispatches.

The ability to model two modes of dispatch: system and company

Within a single run of the program, MAPS performs two separate dispatches of the system generation. In the system dispatch, the entire system is dispatched to serve the load as economically as possible, subject to the constraints imposed by the transmission system. In the company own-load dispatch, each company's resources (including its firm transactions with other companies) are economically dispatched to serve its own load. The results of the two dispatches are then used to calculate the savings that result from the coordinated system dispatch versus the isolated company dispatches. Several methods of cost reconstruction are available to allocate these savings between the buyers and sellers and compute the individual company costs in the system environment.

Furthermore, multiple pools within a system are modeled in MAPS. MAPS has the capability to model economic energy transaction within a company's power pool, if desired in the simulation.

System simulations on an hourly chronological basis in both a Monte Carlo and probabilistic mode

MAPS simulates the system on a chronological hourly basis, modeling the forced outages through either a Monte Carlo or recursive convolution approach. In the Monte Carlo approach, the forced outages on generating units are modeled through the use of random outages. This method is stochastic over the course of the entire year and results in the units being on forced outage for randomly)selected weeks during the year. The number of weeks of outage for each unit is determined by its forced outage rate. Partial outages on the generating units can also be modeled with this method. The random outage method permits accurate treatment of forced outages over the course of the year while allowing each hour to be deterministically dispatched, thus providing for the most accurate treatment of transmission limits when operating in the detailed electrical mode.

MAPS also has the capability of using the more traditional "recursive convolution' technique when it is run in the transportation mode. This methodology convolves the units' forced outages with the loads to develop an equivalent load curve each hour, allowing the calculation of expected output for each of the generating units. In this manner, a unit with a l0% forced outage rate will have a l0% probability of being unavailable for each hour of the year. This methodology is not compatible with the more detailed transmission constraint logic, but can be used with the transportation model and the transfer limits between areas.

Algorithms to minimize production costs, including modeling fuel constraints

The objective of the commitment and dispatch algorithms in MAPS is to determine the most economic operation of the generating units on the system, subject to the operating characteristics of the individual generating units, the constraints imposed by the transmission system, and other operational considerations such as operating and spinning reserve requirements. The economics used for dispatch can be adjusted through the use of penalty factors which can move a unit within the commitment and dispatch ordering.

In MAPS, minimum fuel usage and maximum fuel limits are modeled and enforced on a monthly basis. If the maximum fuel limit is reached, the affected units will be switched to an alternate fuel.

Modeling of emission costs, and variable and fixed O&M costs

MAPS models emission costs, variable O&M costs (in $/MWh and $/fired hour), and fixed O&M costs (in $/kW/year). The user can specify whether the emission costs and variable O&M are to be included in the incremental costs used to determine the order in which the units are dispatched. In addition, the user can specify whether the start-up costs (along with emission costs and variable O&M) should be included in the full-load costs used to determine the order in which the units are committed.

MAPS models two general types of emissions. The first type of emission is a function of the amount of fuel being used. This type would typically be used to model sulfur and particulate emission. The second type of emission is a function of the unit operation, but is not directly related to the amount of fuel. This type could be used to model NOx emissions which can decrease with increased power output.

In addition to the emission rates which are modeled by fuel type or by unit, the user can input, by thermal unit and emission type, the removal efficiency (in per unit) of the emission control equipment, and the removal and trading costs in dollars per ton of emission. The removal cost represents the operating costs associated with emission control equipment. The trading cost can be used to model the costs associated with the emissions that are not removed by the control equipment. These costs could include the costs related to the purchase of emission allowances. Penalty factors on the removal and trading costs can also be input to bias the operation of the units based on their environmental characteristics.

Modeling of dispatchable purchase and sales contracts

MAPS can model internal transactions (purchase and sales contracts) between companies within the system, and external transactions with companies outside of the study system.

The internal transactions can be either "firm" or "economy". Firm transactions between companies can be specified in MW on an hourly basis, or as a minimum and maximum rating (MW) and a monthly energy (MWh) which will be scheduled by . The firm transactions occur regardless of economics. The economy transactions occur between companies in the system dispatch when it is cheaper for a company to purchase energy to serve its load than to generate it with its own units.

The external contracts can also be categorized as "firm" and "economy" . The primary difference is that firm external contracts are evaluated as part of the base dispatch each hour, while economy external contracts involve multiple dispatches each hour to evaluate the price paid for the energy.

Firm external contracts are modeled as unit modifiers located outside of the study system, but in all other respects they are treated the same as any other system generation. Company ownerships are assigned to the units, and they are modeled in the commitment and dispatch along with the "local" generation.

The special feature of the economy external contract logic in MAPS is that multiple dispatches are performed each hour (both with and without each economy external contract) and the price paid for the energy is a function of the change in system operating costs. This total savings is also referred to in MAPS as the delta costs. These total savings from the transactions are divided between the system and the outside world according to a specified percentage. The system savings resulting from an external economy purchase are allocated to those companies that are net buyers of energy. Similarly, any savings from an external economy sale are allocated to those companies that are net sellers of energy.

Modeling of security constraints such as must-run units, minimum generation by geographical area, maximum simultaneous import limits, etc.

In MAPS, the production simulation is formulated as a linear programming (LP) problem where the objective function is to minimize the production costs subject to electrical and business constraints. MAPS models each security constraint as a single constraint in the LP formulation. MAPS derives these constraints from the production costing input data (for example, identified must-run units and minimum down-time for generating units) and from user-specified operating nomograms, such as those often used by system operators to represent voltage and transient stability limits. MAPS monitors the flows on individual transmission lines and interfaces on an hourly basis to ensure that the line or interface limits, or other security constraints such as import limits, are not violated while dispatching the generation system.

MAPS can also consider other user-specified contingencies such as the tripping of lines or groups of lines, or the tripping of load or generation at specified buses. The final generation dispatch developed by MAPS will be secure in the sense that the system will be operating within all of its limits even under the contingency conditions.

Model of reserves (planning, commitment, and spinning) by area or company or for the whole system

During the unit commitment process, MAPS models operating reserve requirements for areas, companies, pools, and the entire system. The operating reserves are calculated based on a percentage of the load, a fixed MW reserve, and a percentage of continuous rating of the largest committed unit.

The total operating reserves can be met by a combination of quick-start reserves (units not actually running but which can be brought on line very quickly) and spinning reserves. The portion of operating reserves that can be met by quick-start reserves can be specified by area, company, pool, or system. The user identifies which units have quick-start capability.

A spinning reserve credit can be taken for unused generation from energy-storage units. The user can also specify the portion of each committed thermal unit that can be applied towards the spinning reserve requirements.

Allow variable simulation time steps to reduce execution time (such as typical week per month)

MAPS has considerable flexibility in the simulation time steps that it models. In its most detailed mode, MAPS studies all of the days in the year on an hourly basis. Through a simple change in input, the program can be directed to study all of the days in the year on a bi-hourly basis, or a typical week per month on an hourly or bi-hourly basis.

The user can specify the starting and ending years of the study period. Within the study period, the user can indicate which years to study and whether the entire year or only a portion of the year is to be simulated.

TRANSMISSION NETWORK

MAPS contains two distinct models for representing the transmission system. The model of primary interest (*the electrical mode*) performs a transmission-constrained production simulation that uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This model captures the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints. In this model, all physical components of the transmission system are modeled, including transmission lines, phase-angle regulators, and HVDC lines. Alternatively, MAPS has the capability to characterize the transmission system in terms of a "transportation model." In this model (*the transportation mode*)transfers between interconnected areas are limited to pre-specified levels during the dispatch of the system generation.

MAPS can also operate in the mode in which both methodologies are used simultaneously. For example, MAPS can operate so that both the scheduled contract flows (transportation model) and actual electrical flows are calculated, with the more restrictive limits applying. Similarly, MAPS can constrain the system based only on the transfer limits between areas while calculating the actual electrical flows throughout the system.

Most discussions about the future of power systems agree that networks will be stressed more than ever before, and the utilities will not have the luxury of observing artificial constraints. For this reason it is important to model the actual electrical flows on the lines in addition to the "transportation flows" between the control areas. MAPS, with both models available, is perfectly suited to model both the current operation of a system and to examine the various ways in which the system might be operated in the future.

Represent transmission flows and limits on an hourly basis

In both the transportation mode and the electrical mode, MAPS calculates and limits the transmission flows on an hourly basis. In the electrical representation, the load and generation are assigned to individual buses and the transmission system is modeled in terms of the individual transmission lines, interfaces (which are groupings of lines), phase-angle regulators (PARs), and HVDC lines. Limits can be specified for the flow on the lines and the operation of the PARs. These limits can change on an hourly basis as a function loads, generation, and flows elsewhere on the system. Examples of the types of operating nomograms that can be modeled in MAPS include:

- transmission line or interface limit as function of area or company load;
- net imports to an area as a function of load;
- simultaneous.imports into an area;
- minimum generation by area.

In the transportation mode, the utility system is modeled as discrete operating areas which contain generation and load. The transmission system is represented in terms of transfer limits on the interfaces between the interconnected areas. These limits can be different for the two directions of interface flow, and can be specified on an hourly basis. These limits can also vary on an hourly basis in response to user-specified conditions as to whether or not specified units are available (for commitment) or have been committed (for dispatch).

The user can control the extent to which will enforce the limits assigned to an interchange path, transmission line, or other system element. Each monitored element is assigned an overload cost in $/MWh; if violating the limit will result in production cost savings greater than or equal to the overload cost, the limit will be ignored. If the monitored element has a small overload cost, it has "soft' limits that will be monitored but will most likely not result in a significant redispatch of the generation. An element with a large overload cost will be modeled with "hard" limits that are strictly enforced and rarely, if ever, violated, necessitating a redispatch of the generation to correct the violations.

Represent various power market participants

Through the appropriate assignment of loads and generation, the various participants in the power market can be represented in MAPS. Integrated utilities would have generation, transmission, and be responsible for serving load. Separate distribution entities would not own any generation but would purchase all of the energy they need to meet their load obligations. Independent power producers would be modeled as companies with generation but no transmission or load. The commitment, dispatch, and cost allocation functions in MAPS itself would represent the independent system operator. The wholesale power broker would be modeled as a company with firm contracts to buy energy from other companies, which would then be resold on a firm or economy basis.

Represent bilateral contracts in the power market

MAPS models bilateral contracts as firm transactions between the selling and buying companies. These contracts can be specified in terms of hourly MW values, or as minimum and maximum MW ratings and available monthly energy that would be scheduled by the program.

OTHER FEATURES

Data Input/Output -- Flexible data entry and storage and customized output reports

The MAPS data is input through data tables that are stored as text files which can be very easily accessed and edited through standard text editors. The table structure is essentially free-format with no stringent requirements that data be input in specific positions within a line. The table structure in MAPS is self-documenting and allows the user to freely insert comments in the data to aid in documentation.

All of the MAPS output is stored in binary files to allow for report generation and customization at a later date. Among the results stored in binary files are the individual unit quantities on an hourly, monthly, annual, and study period basis for the system and own-load dispatches, and the hourly interface flows. The stored results of the transmission analysis when MAPS is run in the electrical mode include the hourly flows and plant outputs, the limiting elements for each hour and the marginal benefit of relaxing each limiting constraint, and the hourly spot prices at specified buses.

This binary data can be accessed through user-developed post-processing programs or through the MAPS Report Analyzer (MRA) that is part of the MAPS software package. The MRA loads the data from the binary files into a very efficient database and allows the user to easily create customized reports and graphs through the use of built-in commands and a simple programming language.

Realistic representation of hydro, pondage, and energy storage scheduling

MAPS offers three distinct representations for modeling hydro plants: hourly modifiers, pondage modifiers, or energy-storage devices. This flexibility allows the program to accurately model each hydro plant based on its operating characteristics.

Hourly modifiers allow the user to specify the actual hour-by-hour operation of the plant in MW. This data can be specified for the 168 hours of a typical week of operation, with the option to change this data on a monthly basis. Alternatively, the hourly operation for the entire year (8,760 or 8,784 hours) can be input. This feature can also be used to model firm company transactions that can be specified on an hourly basis.

Hydro plants can also be modeled as pondage modifiers. Each pondage modifier is defined by a monthly minimum and maximum capacity (MW) and a monthly available energy (MWh). The minimum capacity is base-loaded for all of the hours in the month, representing the run-of-river portion of the plant. The remaining capacity and energy are scheduled in a peak-shaving or valley-filling mode over the month. The user identifies the specific load shape to use for scheduling the plant. Options include the system load, combinations of selected company loads, or combinations of selected area loads.

For energy-storage devices, which include pumped-storage hydro and batteries, MAPS automatically schedules the operation based on economics and the characteristics of the storage device. The characteristics specified include the charging (or pumping) and generating ratings, the maximum storage capacity in MWh, the full-cycle efficiency (which recognizes losses in the pump/generate cycle), and the scheduling period (daily or weekly). The program examines the initial thermal unit commitment to develop a cost curve for the week. This cost curve is then combined with the appropriate chronological load profile to develop an hourly schedule which will minimize costs without violating the storage constraints. This schedule is then "locked in" and the thermal unit commitment process is repeated to develop the final commitment schedule.

For all three hydro representations, the user also specifies the ownership of the plant, energy costs in $/MWh, and the transmission system bus or buses at which the plant is located.

Option for stimulating different water conditions (e.g., low, average, or high streamflows)

MAPS allows the user to develop scenarios for different water conditions through simple modifications to the available energy specified for the pondage modifiers.

The ability to economically dispatch hydro storage subject to hydrological balancing constraints

A complete hydro schedule must take into account navigation, flood control, irrigation, electric power generation, anadromous fish migration, resident fish habitat, wildlife habitat, recreation, water quality and supply in addition to less tangible aspects as protecting cultural and historical sites along the river. Accomplishing all of this in the context of a security constrained production simulation is clearly beyond the scope of MAPS or any other single program.

GE is considering possible enhancements to the hydro modeling in MAPS. With this enhancement, data would be input for each hydro plant that specifies the value or price of the hydro energy as a function of the storage level and the time of year. This price would then be used in doing a combined hydro-thermal dispatch based on economics. The storage level of each hydro plant would recognize the streamflows into the reservoir, including the release from hydro plants located upstream.

Model dispatchable load management strategies and non-dispatchable renewables, and determine regional and utility-specific advantages of DSM programs

MAPS can model some types of dispatchable DSM and load control as thermal generating units with the appropriate characteristics and costs. Load management strategies such as *batteries or thermal energy storage can be modeled as energy-storage devices.*

MAPS models non-dispatchable DSM and load control and renewables such as photovoltaic or wind energy as hourly modifications to the load. This modification can be specified for the 168 hours of a typical week, with the option to change this data on a monthly basis, or by specifying the data for the entire year (8,760 or 8,784 hours)

The generating units used to represent DSM, load control, and renewables can be assigned to the appropriate areas throughout the system to accurately capture the dispersed nature of such resources.

Through the modeling in MAPS of various DSM programs, the production cost benefits for individual utilities and the system as a whole can be readily determined.

Exhibit 6

Supplement No. 11 to Tariff Electric Pa. P.U.C. No. 2

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19101

For List of Communities Served, See Page 4.

Issued January 22, 1997

Effective May 23, 1997

**ISSUED BY: C. A. MC NEILL, JR. - President
and Chief Executive Officer
2301 MARKET STREET
PHILADELPHIA, PA. 19101**

NOTICE.

THIS SUPPLEMENT MAKES CHANGES IN EXISTING RATES

LIST OF CHANGES MADE BY THIS SUPPLEMENT

CHANGES

Net Securitization Adjustment *(Original Page No. 31A)*
Net Securitization Adjustment is added to reflect the rate changes due to the Company's Asset Securitization.

Transition Bond Expense Adjustment (Original Page No. 31B)
Transition Bond Expense Adjustment is added to reconcile the estimated Transition Bond Expense.

Rate R - Residence Service (2nd Revised Page No. 40)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate RT- Residence Time-of-Use Service (2nd Revised Page No. 41)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate R-H - Residential Heating Service (2nd Revised Page No. 42)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

CAP Rate (2nd Revised Page No. 42A)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate OP - Off-Peak Service (2nd Revised Page No. 43)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate R-S - Solar Residence Service (2nd Revised Page No. 43A)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate G-S - General Service *(2nd Revised Page No. 44)*
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate P-D - Primary Distribution Power (2nd Revised Page No. 46)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate H-T High Tension Power (2nd Revised Page No. 47)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate P-O-L Private Outdoor Lighting (3rd Revised Page No. 48)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate SL-P Street Lighting in City of Philadelphia (2nd Revised Page No. 50)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate SL-S Street Lighting - Suburban Divisions (2nd Revised Page No. 53)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate SL-E Street Lighting Customer Owned Facilities (2nd Revised Page No. 55)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate TL Traffic Lighting Service (2nd Revised Page No. 57)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate BLI Borderline Interchange Service *(2nd Revised Page No. 58)*
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

Rate EP Electric Propulsion (2nd Revised Page No. 59)
Net Securitization Adjustment and Transition Bond Expense Adjustment are added.

TABLE OF CONTENTS

NET SECURITIZATION ADJUSTMENT (NSA) (C)

In addition to the net charges provided for in this tariff, values as indicated in the table below will be applied to service on and after xxx xx, 1997.

The NSA is comprised of two separate factors, the Securitization Rate Reduction and the Intangible Transition Charge. The factors as described below will become effective on 10 days notice to the Commission.

Securitization Rate Reduction (SRR)

The SRR is a credit to the Company's base rate charges, expressed as a percentage of such charges, reflecting a revenue requirement reduction arising from the Company's securitization of generation-related costs pursuant to Sections 2808 and 2812 of the Pennsylvania Public Utility Code. The SRR will be recalculated whenever the level of revenue requirement reduction due to the level of asset securitization changes, as evidenced by the issuance date the of the Transition Bonds.

Intangible Transition Charge (ITC)

The ITC is a charge that is added to, and expressed as a percentage of, the Company's base rate charges reflecting the revenue requirement necessary to amortize the Qualified Transition Expense (QTE) principal balance. The ITC will be recalculated:

(1) whenever new Transition Bonds are issued as evidenced by the issuance date of the bonds.

(2) periodically, to reconcile unamortized QTE principal balance, as mandated by the terms and conditions of the Transition Bond agreements.

Effective Rate Table

Rate Class	SRR	ITC	NSA
R	xx.xxxx%	xx.xxxx%	xx.xxxx%
RT	xx.xxxx%	xx.xxxx%	xx.xxxx%
R-H	xx.xxxx%	xx.xxxx%	xx.xxxx%
CAP	xx.xxxx%	xx.xxxx%	xx.xxxx%
OP	—	—	—
R-S	xx.xxxx%	xx.xxxx%	xx.xxxx%
GS	xx.xxxx%	xx.xxxx%	xx.xxxx%
PD	xx.xxxx%	xx.xxxx%	xx.xxxx%
HT	xx.xxxx%	xx.xxxx%	xx.xxxx%
POL	—	—	—
SL-P	—	—	—
SL-S	—	—	—
SL-E	—	—	—
TL	—	—	—
BLI	xx.xxxx%	xx.xxxx%	xx.xxxx%
EP	xx.xxxx%	xx.xxxx%	xx.xxxx%

(C) Denotes Change

TRANSITION BOND EXPENSE ADJUSTMENT (TBEA) (C)

In addition to the net charges provided for in this tariff, values as indicated in the table below will be applied to all service on and after xxx 1997. The TBEA will become effective on 60 days notice to the Commission and will be subject to an annual reconciliation and review process.

The TBEA provides a reconciliation mechanism to collect or refund the difference between estimated Transition Bond expenses that have been incorporated into the issuance of Transition Bonds being recovered in the Intangible Transition Charge and the actual Transition Bond expenses. Transition Bond expenses are defined as expenses associated with the issuance of and use of proceeds from Transition Bonds.

Effective Rate Table

Rate Class	TBEA
R	xx.xxxx%
RT	xx.xxxx%
R-H	xx.xxxx%
CAP	xx.xxxx%
OP	—
R-S	xx.xxxx%
GS	xx.xxxx%
PD	xx.xxxx%
HT	xx.xxxx%
POL	—
SL-P	—
SL-S	—
SL-E	—
TL	—
BLI	xx.xxxx%
EP	xx.xxxx%

(C) Denotes Change

RATE R RESIDENCE SERVICE

AVAILABILITY.

Single-phase electric service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for the domestic requirements of its members when such service is supplied through one meter. Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered for their basic electric service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost-sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space is used for the conduct of business by a person residing therein; (e) farm purpose uses by an individual employing the natural processes of growth for the production of grain, stock, dairy, poultry, garden truck, or other agricultural products.

The term does NOT include service to: (a) Premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) farms operated principally to sell, prepare, or process products produced by others, or farms using air conditioning for climatic control in conjunction with growth processes (except those customers receiving such service as of August 2, 1969); (e) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37-1/2 amperes at 240 volts.

CURRENT CHARACTERISTICS.

Standard single-phase secondary service.

MONTHLY RATE TABLE.

CUSTOMER CHARGE: $5.10

ENERGY CHARGE PRICES:
SUMMER MONTHS. (June through September)
13.05¢ per kWh for the first 500 kWh per dwelling unit
14.91¢ per kWh for additional kWh.

WINTER MONTHS. (October through May)
13.05¢ per kWh.

MINIMUM CHARGE: The minimum charge per month will be the Customer Charge.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

PAYMENT TERMS.

Standard.

(C) Denotes change.

RATE RT RESIDENCE TIME-OF-USE SERVICE

AVAILABILITY.

Single-phase electric service in the entire territory of the Company to the dwelling and appurtenances of a single private family for the domestic requirements of its members when such service is supplied through one meter. Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost-sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space if used for the conduct of business by a person residing therein; (e) farm purpose uses by an individual employing the natural processes of growth for the production of grain, stock, dairy, poultry, garden truck, or other agricultural products.

The term does NOT include service to: (a) Premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) farms operated principally to sell, prepare, or process products produced by others, or farms using air conditioning for climatic control in conjunction with growth processes (except those customers receiving such service as of August 2, 1969); (e) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37-1/2 amperes at 240 volts.

CURRENT CHARACTERISTICS.

Standard single-phase secondary service.

DEFINITION OF PEAK-HOURS.

On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as on-peak hours.

MONTHLY RATE TABLE.

CUSTOMER CHARGE: $10.19

ENERGY CHARGE PRICES:
SUMMER MONTHS. (June through September)
7.10¢ per off-peak kWh
24.05¢ per on-peak kWh.
WINTER MONTHS. (October through May)
7.10¢ per off-peak kWh
22.19¢ per on-peak kWh.

MINIMUM CHARGE: The minimum charge per month will be the Customer Charge.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

CONTRACT TERM.

Not less than twelve months.

PAYMENT TERMS.

Standard.

(C) Denotes change.

RATE R-H RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single-phase electric service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for domestic requirements when such service is supplied through one meter and where the dwelling is heated by specified types of electric space heating systems. The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling, (b) heat pump installations where all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where all of the supplementary heating required is supplied by non-electric energy sources and/or by electric energy sources served on Rate OP Off-Peak Service. All space heating installations must meet Company requirements. This rate schedule is not available for commercial, institutional or industrial establishments.

Wood, solar, wind, water, and biomass systems may be used to supply a portion of the heating requirements in conjunction with service supplied hereunder. Any Customer system of this type that produces electric energy may not be operated concurrently with service supplied by the Company except under written agreement setting forth the conditions of such operation as provided by and in accordance with the provisions of the Auxiliary Service Rider.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date, must be individually metered.

(Not available when the source of supply is service purchased from
a neighboring Company under Rate BLI Borderline Interchange Service.)

CURRENT CHARACTERISTICS.

Standard single-phase secondary service.

MONTHLY RATE TABLE.

CUSTOMER CHARGE: $5.10
ENERGY CHARGE PRICES:
SUMMER MONTHS. (June through September)
13.05¢ per kWh for the first 500 kWh per dwelling unit
14.91¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
13.05¢ per kWh for the first 600 kWh per dwelling unit
6.37¢ per kWh for additional kWh.

MINIMUM CHARGE: The minimum charge per month will be the Customer Charge.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

COMBINED RESIDENTIAL AND COMMERCIAL SERVICE.

Where a portion of the service supplied is used for commercial purposes, the appropriate general service rate is applicable to all service; or, at the option of the Customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

PAYMENT TERMS.

Standard.

(C) Denotes change.

CAP RATE

(Experimental Rate - limited to 5000 customers)

AVAILABILITY.

To payment-troubled customers who are currently served under or otherwise qualify for Rate R or Rate RH (does not include multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for this rate and must demonstrate annual household gross income below 150% of the Federal Poverty guidelines.

Customers with annual household gross incomes below 100% of the Federal poverty income guidelines will be eligible for Customer Assistance Program (CAP) Rate I.

Customers with annual household gross incomes between 100% and 150% of the Federal poverty income guidelines will be eligible for Customer Assistance Program (CAP) Rate II.

Certification by various State agencies that a customer is receiving certain government assistance payments may be used where possible to expedite the eligibility process. These payments include (but are not limited to) AFDC, SSI, Food Stamps, PACE and Medicaid. Information available from the Pa. Department of Revenue may also be used where appropriate to expedite the process.

A process will be established to provide verification of eligibility for customers who do not fit the above processes. Asset testing will also be used where necessary and appropriate.

Customers being considered for the CAP Rates will be required to:

* Waive certain privacy rights to enable PECO Energy to effectively conduct the above certification process.
* Apply for and assign to PECO Energy at least one energy assistance grant from the Commonwealth.
* Participate in various energy education and conservation programs facilitated by PECO.

MONTHLY RATE TABLE.

Rate R customers

CAP Rate I

Customer Charge: $5.10

ENERGY CHARGE PRICES:

6.31¢ per kWh for the first 500 kWh

13.05¢ per kWh for additional kWh

CAP Rate II

Customer Charge: $5.10

ENERGY CHARGE PRICES;

9.68¢ per kWh for the first 500 kWh

13.05¢ per kWh for additional kWh

Rate RH customers

CAP Rate I

Customer Charge: $5.10

ENERGY CHARGE PRICES:

SUMMER MONTHS. (June through September)

6.31¢ per kWh for the first 500 kWh

13.05¢ per kWh for additional kWh

WINTER MONTHS (October through May)

6.31¢ per kWh for all kWh

CAP Rate II

Customer Charge: $5.10

ENERGY CHARGE PRICES:

SUMMER MONTHS. (June through September)

9.68¢ per kWh for the first 500 kWh

13.05¢ per kWh for additional kWh

WINTER MONTHS (October through May)

9.68¢ per kWh for the first 500 kWh

6.31¢ per kWh for additional kWh

MINIMUM CHARGE: *The minimum charge per month will be the customer charge.*

STATE TAX ADJUSTMENT CLAUSE applies to these rates.

NET SECURITIZATION ADJUSTMENT applies to these rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

(C) Denotes change

RATE OP OFF-PEAK SERVICE

AVAILABILITY.

In conjunction with Rates R, RT, R-H and with residence service under Rate GS, for any Customer receiving service at 120/240 volts, 3 wires, or 120/208 volts, 3 wires, for the operation of 240-volt or 208-volt domestic equipment of a type approved by the Company. Any load connected for service under Rate OP may not be connected for service under any other rate during the period that service under Rate OP is interrupted. Service will be interrupted during on-peak periods as established by the Company. This rate is not available when the source of supply is service purchased from a neighboring company under a borderline-purchase agreement.

SPECIAL RULES AND REGULATIONS.

The normal control device furnished by the Company has a limited capacity. The Customer shall notify the Company before connecting any load in addition to an existing water heater. If necessary, the Company will install a control device with a rating of 100 amperes to accommodate the additional 240-volt controlled load. For controlled loads larger than 100 amperes the control device shall be furnished, installed and maintained by the Customer.

Service may be interrupted for a total of not more than 6-1/2 hours per day during scheduled periods which may vary from Customer to Customer.

The Company has a program to replace seven-day clock control devices as they fail with five-day radio-control devices which provide uninterrupted service on Saturdays, Sundays and holidays.

MONTHLY RATE TABLE.

CUSTOMER CHARGE: $4.58 per month.

ENERGY CHARGE: 5.48¢ per kilowatt-hour

MINIMUM CHARGE: The minimum charge per month will be the Customer Charge.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. **(C)**

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. **(C)**

PAYMENT TERMS.

Standard.

(C) Denotes change

RATE R-S SOLAR RESIDENCE SERVICE

AVAILABILITY

Single-phase electric service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for the domestic requirements of its members, that has installed solar panels or similar device or devices that are, in PECO Energy's sole judgment, a bona fide technology for use in generating electricity using energy from the Sun, and that will be operated in parallel with the Company's system. The customer's equipment must conform to the installation requirements contained in the Company's published "Requirements For Parallel Operation Of Non-Utility Generation." The Company will modify its distribution and transmission facilities as necessary to interconnect with the Customer at a single point. A customer will be charged for all modifications, additions or retirements made to provide the interconnection, in accordance with the "Requirements for Parallel Operation of Non-Utility Generation". This rate schedule is not available for commercial, institutional or industrial establishments.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other options of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost-sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space if used for the conduct of business by a person residing therein; (e) farm purpose uses by an individual employing the natural processes of growth for the production of grain, stock, dairy, poultry, garden truck, or other agricultural products.

The term "residence service" does NOT include service to: (a) premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) farms operated principally to sell, prepare, or process products produced by others, or farms using air conditioning for climatic control in conjunction with growth processes (except those customers receiving such service as of August 2, 1969); (e) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37-1/2 amperes at 240 volts.

(Not available when the source of supply is service purchased from
a neighboring Company under Rate BLI Borderline Interchange Service.)

METERING/BILLING PROVISIONS.

A customer may select one of the following two billing and metering options:

(a) A ratcheted meter may be installed that records only energy sales to the customer. If the solar panels or other device generate more electricity than the customer uses in any billing month, then the customer will not be charged for any energy usage, but the customer will not be paid by the Company for the excess energy delivered to PECO Energy. No dual metering charge shall apply.

(b) Two meters may be installed. One will measure the energy delivered by the Company that the customer uses, and the other will measure the energy delivered to the Company from the customer that is generated by the customer's solar panels or other qualified device. If, in any billing month, the amount of energy delivered by the Company that the customer uses is greater than the amount of energy the customer delivered to the Company, then the Company will bill the customer for the difference. If, in any billing month, the amount of energy delivered by the Company that the customer uses is less than the amount of energy the customer delivered to the Company, the Company will pay the customer for the excess using the monthly average PJM billing rate. A monthly meter charge shall apply if this billing and metering option is selected.

CURRENT CHARACTERISTICS.

Standard single-phase secondary service.

MONTHLY RATE TABLE FOR NET ENERGY USED BY CUSTOMER.

CUSTOMER CHARGE: $5.10
DUAL METERING CHARGE: $4.46
ENERGY CHARGE PRICES:
SUMMER MONTHS. (June through September)
13.05¢ per kWh for the first 500 kWh per dwelling unit
14.91¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
13.05¢ per kWh.
MINIMUM CHARGE: The minimum charge per month will be the Customer Charge and Dual Meter Charge.
STATE TAX ADJUSTMENT CLAUSE applies to this rate.
NET SECURITIZATION ADJUSTMENT applies to this rate. (C)
TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

CONTRACT TERM.

Not less than twelve months.

PAYMENT TERMS.

Standard

(C) Denotes Change

RATE GS GENERAL SERVICE

AVAILABILITY.
Electric service through a single metering installation for offices, professional, commercial or industrial establishments, governmental agencies, and other applications outside the scope of the Residence Service rate schedules.

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service.

MONTHLY RATE TABLE.
CUSTOMER CHARGE:
$ 6.63 for single-phase service without demand measurement, or
$ 8.67 for single-phase service with demand measurement, or
$23.45 for polyphase service.
ENERGY CHARGE:
22.14¢ per kWh for the first 80 hours' use of billing demand
*11.24¢ per kWh for the next 80 hours' use of billing demand
7.67¢ per kWh for additional use; except
4.25¢ per kWh over both 400 hours' use of billing demand and 2,000 kWh.

* During October through May this block is eliminated.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

DETERMINATION OF DEMAND. The billing demand will be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months; or where load tests indicate a demand of five or more kilowatts; or where the Heating Modification is applied; or where the Customer requests demand measurement. Measured demands will be determined to the nearest 0.1 of a kilowatt but will not be less than 1.2 kilowatts, and will be adjusted for power factor in accordance with the Rules and Regulations.

For those customers with demand measurement, during October through May the billing demand will not be less than 40% of the highest billing demand in the preceding months of June through September, nor less than the minimum value stated in the contract for service. If a measured demand Customer has less than 1,100 monthly kilowatt-hours of use, the monthly billing demand will be the measured demand or the metered monthly kilowatt-hours divided by 175 hours, whichever is less, but not less than 40% of the highest billing demand in the preceding months of June through September, nor less than 1.2 kilowatts.

For those customers without demand measurement, the monthly billing demand will be computed by dividing the metered monthly kilowatt-hours by 175 hours. The computed demand will be determined to the nearest 0.1 of a kilowatt, but will not be less than 1.2 kilowatts.

MINIMUM CHARGE.
The monthly minimum charge for customers without demand measurement will be the Customer Charge. The monthly minimum charge for customers with demand measurement will be the Customer Charge, plus a charge of $6.17 per kW of billing demand.

HEATING MODIFICATION.
Wood, solar, wind, water, and biomass systems may be used to supply a portion of the heating requirements in conjunction with service supplied hereunder. Any Customer system of this type that produces electric energy may not be operated concurrently with service supplied by the Company except under written agreement setting forth the conditions of such operation as provided by and in accordance with the provisions of the Auxiliary Service Rider.

METERING.
A. Single Meter.
Applicable where an area is heated solely by permanently connected electric space heating installations (1) acceptable to the Company, (2) sensitive to outdoor temperature and (3) not less than 5 kilowatts. Qualifying electric heating systems are (1) electric resistance coils, (2) electric resistance baseboards, (3) electric boilers and (4) heat pumps with electric back-up.

(Continued)

(C) Denotes Change

RATE PD PRIMARY-DISTRIBUTION POWER

AVAILABILITY.

Untransformed electric service from the primary supply lines of the Company's distribution system where the Customer installs, owns, and maintains any transforming, switching and other receiving equipment required. However, standard primary service is not available in areas where the distribution voltage has been changed to either 13 kV or 33 kV unless the Customer was served with standard primary service prior to the conversion of the area to either 13 kV or 33 kV. This rate is available only for service locations served on this rate on July 6, 1987 as long as the original primary service has not been removed. PECO may refuse to increase the load supplied to a customer served under this rate when, in PECO's sole judgment, any transmission or distribution capacity limitations exist. If a customer changes the billing rate of a location being served on this rate, PECO may refuse to change that location back to Rate PD when, in PECO's sole judgment, any transmission or distribution capacity limitations exist.

CURRENT CHARACTERISTICS.

Standard primary service.

MONTHLY RATE TABLE.

CUSTOMER CHARGE: $275.28
CAPACITY CHARGE: $9.25 per kW of billing demand

ENERGY CHARGE PRICES:
9.77¢ per kWh for the first 150 hours' use of billing demand
6.43¢ per kWh for the next 150 hours' use of billing demand
3.14¢ per kWh for additional use.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

DETERMINATION OF BILLING DEMAND.

The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, during the eight months of October through May the billing demand will not be less than 40% of the maximum demand specified in the contract nor less than 80% of the highest billing demand in the preceding months of June through September.

MINIMUM CHARGE.

The monthly minimum charge shall be the Customer Charge, plus the capacity charge for the monthly billing demand.

TERM OF CONTRACT.

The initial contract term shall be for at least three years.

PAYMENT TERMS.

Standard.

(C) Denotes Change

RATE HT HIGH-TENSION POWER

AVAILABILITY.

Untransformed electric service from the Company's standard high-tension lines, where the Customer installs, owns, and maintains, any transforming, switching and other receiving equipment required.

CURRENT CHARACTERISTICS.

Standard high-tension service.

MONTHLY RATE TABLE.

CUSTOMER CHARGE: $286.86

CAPACITY CHARGE: $12.76 per kW of billing demand.

ENERGY CHARGE PRICES:

8.29¢ per kWh for the first 150 hours' use of billing demand

5.50¢ per kWh for the next 150 hours' use of billing demand, but not more than 7,500,000 kWh

2.74¢ per kWh for additional use.

TIME-OF-USE ADJUSTMENT:

Customers with measured demand of 2,000 kW or greater will be given a credit for energy use during off-peak hours and will be subject to an additional charge for energy use during on-peak hours. On-peak hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-peak hours are defined as the hours other than those specified as on-peak hours. The credits and charges are as follows:

	Summer Months (June through September)	Winter Months (October through May)
Off-peak credit............	0.21¢ per kWh	0.21¢ per kWh
On-peak charge..........	0.57¢ per kWh	0.22¢ per kWh

HIGH VOLTAGE DISCOUNT:

For customers supplied at	33,000 volts: 7¢ per kW of measured demand.
For customers supplied at	69,000 volts: 30¢ per kW for first 10,000 kW of measured demand.
For customers supplied over	69,000 volts: 30¢ per kW for first 100,000 kW of measured demand.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.
NET SECURITIZATION ADJUSTMENT applies to this rate. (C)
TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

DETERMINATION OF BILLING DEMAND.

The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, during the eight months of October through May the billing demand will not be less than 40% of the maximum demand specified in the contract nor less than 80% of the highest billing demand in the preceding months of June through September.

DELIVERY POINTS.

Where the load of a Customer located on single or contiguous premises becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the Customer, an additional separate delivery point may be established for such premises upon the written request of the Customer and billing continued as if the service were being delivered and metered at a single point, provided such multi-point delivery is not disadvantageous to the Company.

MINIMUM CHARGE.

The monthly minimum charge shall be the Customer Charge, plus the capacity charge for the monthly billing demand, less the supply voltage discount where applicable.

PAYMENT TERMS.

Standard.

TERM OF CONTRACT.

The initial contract term shall be for at least three years. This TERM OF CONTRACT may be modified by the application of either the Curtailment HT Rider or Large Interruptible Load Rider.

(C) Denotes Change

RATE POL PRIVATE OUTDOOR LIGHTING

AVAILABILITY.

Outdoor lighting of sidewalks, driveways, yards, lots and similar places, outside the scope of service under Rate SL-P, SL-S and SL-E.

MONTHLY RATE TABLE.

	PRICE PER LIGHTING UNIT	
MERCURY-VAPOR LAMPS-Size of Lamp	Ltg. Unit Attached to Existing Company Pole	Ltg. Unit Attached to Customer's Pole
100 Watts (nominally 4,000 Lumens)	$12.72	$11.45
175 Watts (nominally 8,000 Lumens)	17.27	16.05
250 Watts (nominally 12,000 Lumens)	21.30	20.21
400 Watts (nominally 20,000 Lumens)	27.48	26.05
400 Watts Floodlight (nominally 22,000 Lumens)	29.72	28.29
SODIUM-VAPOR LAMPS-Size of Lamp	Ltg. Unit Attached to Existing Company Pole	Ltg. Unit Attached to Customer's Pole
70 Watts (nominally 5,800 Lumens)	$17.39	$16.15
250 Watts (nominally 25,000 Lumens)	27.70	26.27
400 Watts (nominally 50,000 Lumens)	30.41	28.98
400 Watts Floodlight (nominally 50,000 Lumens)	32.64	31.21

(Service to the above listed Mercury-Vapor Lamps and Sodium-Vapor Lamps will not be available after January 1, 1996 to new customers or existing customers for new or replacement luminaires. The Company will continue to perform lamp renewals and replace photocells as necessary. The Company will not replace defective or broken mercury vapor or sodium vapor luminaires, including ballasts. In such cases, the customer must take service under one of the current lighting unit options.)

	PRICE PER LIGHTING UNIT	
STANDARD METAL HALIDE LAMPS-Size of Lamp	Ltg. Unit Attached to Existing Company Pole	Ltg. Unit Attached to Customer's Pole
400 Watts (nominally 36,000 Lumens)	$32.14	$30.75
1000 Watts (nominally 110,000 Lumens)	56.30	54.91
STANDARD HIGH PRESSURE SODIUM VAPOR LAMPS-Size/Lamp	Ltg. Unit Attached to Existing Company Pole	Ltg. Unit Attached to Customer's Pole
70 Watts (nominally 5,800 Lumens)	$19.55	$18.16
100 Watts (nominally 9,500 Lumens)	20.67	19.28
150 Watts (nominally 16,000 Lumens)	22.59	21.20
250 Watts (nominally 25,000 Lumens)	26.54	25.14
400 Watts (nominally 50,000 Lumens)	32.20	30.80

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

GENERAL PROVISIONS.

1. Standard Lighting Unit. A Standard Lighting Unit shall be a Cobra Head or Floodlight comprised of a bracket, the lead wires and a luminaire, including lamp, reactor and control.

2. Standard Installations. In connection with the standard service provided herein, the Company will install, own and maintain all facilities within highway limits, and all standard service-supply lines and all Lighting Units.

The Customer will install, own and maintain all poles on the Customer's property and all service extensions on the Customer's property from the Company's standard service-supply lines.

Investment by the Company under standard conditions of supply will be limited to that warranted by three times the annual non-fuel related base revenue in prospect, any additional investment to be assumed by the Customer.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other distribution facilities are underground, supply may be underground.

For underground supply furnished at the request of the Customer where aerial supply would be normal, the Company will assume the cost up to the amount it would normally have invested and the additional cost shall be assumed by the Customer. (C)

(Continued)

(C) Denotes Change

RATE SL-P STREET LIGHTING IN CITY OF PHILADELPHIA

AVAILABILITY.

Only to a governmental agency, municipal, state or federal, for outdoor lighting of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder, for the safety and convenience of the public within the City of Philadelphia by incandescent filament, mercury-vapor, fluorescent or sodium-vapor lamps of standard sizes and types approved by the Company where the Customer installs, owns and maintains all Utilization Facilities as hereinafter defined. Service will be supplied under this rate for street Lighting Units supported in a conventional manner such as on poles, posts, brackets or hangers, and under conditions of installation and supply acceptable to the Company.

CHARACTERISTICS OF SUPPLY.

Service under this rate will be from series 6.6 ampere circuits or from standard single-phase secondary circuits, as specified by the Company, except that, where conditions require, or where existing standard secondary circuits are not available, the Company at its option may supply service from nonstandard secondary circuits, providing nominally 240 volts.

MONTHLY RATE TABLE.

FACILITIES CHARGE PRICES:

For Lighting Units in service as of the fifteenth day of the month.

$ 8.64 per Lighting Unit supplied from standard secondary (aerial or underground) circuits where the Customer owns the individual control for such Lighting Unit.

$ 9.24 per Lighting Unit supplied from aerial (series or secondary) circuits *where the Company provides group controls.*

$12.89 per Lighting Unit supplied from underground (series or secondary) circuits where the Company provides group controls.

CAPACITY CHARGE PRICE:

0.37¢ per watt.

ENERGY CHARGE PRICE:

3.84¢ per kWh of energy billed.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

LIGHTING UNIT

A Lighting Unit shall comprise each lighting installation which is separately connected to a delivery point on the Company's series or secondary circuit.

DETERMINATION OF BILLING DEMAND.

The wattage, expressed to the nearest tenth of a watt, of a Lighting Unit shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of wattages of all Lighting Units in service as of the fifteenth day of a month shall constitute the billing demand for the month.

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Lighting Unit shall be computed to the nearest kilowatt-hour as the product of one-thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules approved by the authorized representatives of the Customer and the Company. The aggregate of the kilowatt-hours thus computed for all Lighting Units in service as of the fifteenth day of a month shall constitute the energy billed for the month.

(Continued)

(C) Denotes Change

RATE SL-S STREET LIGHTING-SUBURBAN DIVISIONS

AVAILABILITY.

Outdoor lighting of streets, highways, bridges, parks and similar places for the safety and convenience of the public in *Suburban Divisions.*

RATE TABLE - MANUFACTURER'S RATING OF LAMP SIZES.

Incandescent Filament Lamps

Size of Lamp	Billing Watts	Rate per Year
320 Lumens	32	$ 99.26
600 "	58	138.30
0 1,000 "	103	194.00
2,500 "	202	266.96
6,000 "	448	304.58
10,000 "	690	364.64

For each Customer, the supply of energy for incandescent filament lamps is restricted to the total of each rating in service on May 10, 1980; except that for 320 lumen and 600 lumen lamps the supply is restricted for any Customer to the total of such rating in service on October 15, 1963 and in each succeeding year beginning January 1, 1964, to the number of each rating in service on January first of each such year.

Mercury Vapor Lamps

Size of Lamp	Billing Watts	Rate per Year
Nominally 4,000 Lumens	115	$228.29
" 8,000 "	191	241.10
" 12,000 "	275	257.08
" 20,000 "	429	301.99
" 42,000 "	768	430.18
" 59,000 "	1,090	484.90

Sodium-Vapor Lamps

Size of Lamp	Billing Watts	Rate per Year
Nominally 5,800 Lumens	94	$226.58
" 9,500 "	131	246.35
" 16,000 "	192	276.69
" 25,000 "	294	314.35
" 50,000 "	450	374.54

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

GENERAL PROVISIONS.

1. Service. The lighting service will be operated on an all-night, every-night lighting schedule of approximately 4,100 hours annual burning time (average monthly burning hours = 341.11 hours), under which lights are turned on after sunset and off before sunrise. It includes the supply of lamps and their removal when burned out or broken.

2. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the Customer to a pro rata reduction in the street lighting bill for the hours of failure if such for the hours of failure if such failure continues for a period in excess of 12 hours after the notice is received. Allowances will not be made for outages resulting from the Customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

(Continued)

(C) Denotes Change

RATE SL-E STREET LIGHTING CUSTOMER-OWNED FACILITIES

AVAILABILITY.

To any governmental agency outside of the City of Philadelphia for outdoor lighting of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder for the safety and convenience of the public where all of the utilization facilities, as defined in Terms and Conditions in this rate schedule, are installed, owned and maintained by a governmental agency.

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers. All facilities and their installation shall be approved by the Company.

MONTHLY RATE TABLE.

SERVICE LOCATION CHARGE PRICE:
$10.01 per location.
CAPACITY CHARGE PRICE:
0.276¢ per watt.
ENERGY CHARGE PRICE:
1.741¢ per kWh of energy billed.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

SERVICE LOCATION.

A service location shall comprise each lighting installation which is separately connected to a delivery point on the Company's secondary circuit.

DETERMINATION OF BILLING DEMAND.

The wattage, expressed to the nearest tenth of a watt, of a Service Location shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of wattages of all Service Locations in service shall constitute the billing demand for the month.

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Service Location shall be computed to the nearest kilowatt-hour as the product of one-thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions, Paragraph 6 Service. The aggregate of the kilowatt-hours thus computed for all Active Service Locations shall constitute the energy billed for the month.

TERMS AND CONDITIONS.

1. Ownership of Utilization Facilities.
   a. Service Locations Supplied from Aerial Circuits: Customer shall provide, own and maintain the Utilization Facilities comprising the brackets, hangers, luminaries, lamps, ballasts, transformers, individual controls, conductors, molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location.
   The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the Customer to install thereon the said Utilization Facilities.

   b. Service Locations Supplied from Underground Circuits: Customer shall provide, own and maintain the Utilization Facilities comprising the supporting pole or post, foundation with 90-degree pipe bend, brackets or hangers, luminaries, lamps, ballasts, transformers, individual controls, conductors and conduits from the lamp receptacles to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a delivery point designated by the Company on its secondary voltage circuit, and shall assume all costs of installing such utilization facilities.
   Except as provided in Paragraph 4 Supply Facilities, the Company shall own conduit from the distribution circuit to the 90-degree pipe bend, shall own conductors from its distribution system to the designated delivery point and shall provide sufficient length of conductors for splicing at the designated delivery point or in the post base where sidewalk level access is provided.

(Continued)

(C) Denotes Change

RATE TL TRAFFIC LIGHTING SERVICE

AVAILABILITY.
To any municipality using Company's standard service for electric traffic signal lights installed, owned and maintained by the municipality.

CURRENT CHARACTERISTICS.
Standard single-phase secondary service.

RATE.

11.41¢ per kWh.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. **(C)**

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. **(C)**

SPECIAL RULES AND REGULATIONS.
The use of energy will be estimated by the Company on the basis of the size of lamps and controlling apparatus and the burning-hours. The Customer shall immediately notify the Company whenever any change is made in the equipment or the burning-hours, so that the Company may forthwith revise its estimate of the energy used.

The Company shall not be liable for damage to person or property arising, accruing or resulting from the attachment of *the signal equipment to its poles, wires, or fixtures.*

MINIMUM CHARGE.
$3.56 per month per service installation.

TERM OF CONTRACT.
The initial contract term for each signal light installation shall be for at least one year.

PAYMENT TERMS.
Standard.

(C) *Denotes Change*

RATE BLI BORDERLINE INTERCHANGE SERVICE

AVAILABILITY.
Electric service supplied under reciprocal agreements, to neighboring electric utilities for resale in their adjacent territory at delivery points where the Company in its judgment can provide capacity in excess of the requirements of present and prospective customers in its own territory and for periods fixed by contract and terminable after the expiration of the initial term if capacity is no longer available.

CURRENT CHARACTERISTICS.
Standard primary or secondary service.

MONTHLY RATE TABLE.

INVESTMENT CHARGE:
An amount equal to 1% per month on the additional investment in facilities required to deliver and meter the service supplied.

ENERGY CHARGE:
14.86¢ per kWh.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. (C)

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. (C)

MEASUREMENT.
The energy delivered may be metered or may be estimated from the purchaser's resales plus an agreed-upon correction to cover transformation and distribution losses.

TERM OF CONTRACT.
The initial contract term shall be for at least five years, and thereafter from year to year until terminated by 60 days' notice from either party to the other.

PAYMENT TERMS.
Payment of amounts billed shall be made within 15 days from date of bill.

(C) Denotes Change

RATE EP ELECTRIC PROPULSION

AVAILABILITY.

This rate is available only to the National Rail Passenger Corporation (AMTRAK) and to the Southeastern Pennsylvania Transportation Authority (SEPTA) for untransformed electric service from the Company's standard high-tension lines, where the Customer installs, owns, and maintains any transforming, switching and other receiving equipment required and where the service is supplied for the operation of electrified transit and railroad systems and appurtenances.

CURRENT CHARACTERISTICS.

Standard sixty hertz (60 Hz) high-tension service.

MONTHLY RATE TABLE.

SERVICE CHARGE: $1,243.85 per delivery point

CAPACITY CHARGE: $ 16.46 per kW.

ENERGY CHARGE: 2.74¢ per kWh.

TIME-OF-USE ADJUSTMENT:

There will be a credit for energy use during off-peak hours and an additional charge for energy use during on-peak hours. On-peak hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight *Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will* end at 4:00 pm on Fridays. Off-peak hours are defined as the hours oher than those specified as on-peak hours. The credits and charges are as follows:

	Summer Months (June through September)	Winter Months October through May)
Off-peak credit	0.21¢ per kWh	0.21¢ per kWh
On-peak charge	0.57¢ per kWh	0.22¢ per kWh

HIGH VOLTAGE DISCOUNT:

For delivery points supplied at 33,000 volts: 7¢ per kW
For delivery points supplied at 69,000 volts: 30¢ per kW for first 10,000 kW of measured demand.
For delivery points supplied over 69,000 volts: 30¢ per kW for first 100,000 kW of measured demand.

STATE TAX ADJUSTMENT CLAUSE applies to this rate.

NET SECURITIZATION ADJUSTMENT applies to this rate. **(C)**

TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate. **(C)**

DETERMINATION OF BILLING DEMAND.

The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 5,000 kilowatts. Additionally, during the eight months of October through May the billing demand will not be less than 40% of the maximum demand specified in the contract nor less than 80% of the highest billing demand in the preceding months of June through September.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS

If the load of a Customer located at a delivery point becomes greater than the capacity of the circuits established by the Company to supply the Customer at that delivery point, upon the written request of the Customer, the Company will establish a new delivery point and bill the Customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to *the first delivery point.*

(C) Denotes Change

Exhibit 7

Response to the Commission's Proposed Pre-Filing Guidelines

Filing Guidelines

Intangible Transition Charges

A. General Guidelines

Q1. The utility should include a statement of reasons for the filing. This should be presented within the context of the language of the Act.

A1. Mr. Hill describes in his testimony the reasons for this filing.

Q2. In its filing, the utility must provide a complete and adequate accounting of it's transition or stranded costs, detailed information regarding the utility's proposal for sale of intangible transition property or the issuance of transition bonds and information regarding the utilities planned use of the proceeds of the sale or issuance.

A2. Messrs. Cohn and Hill provide in their testimony and supporting exhibits a complete accounting of PECO's estimated transition and stranded costs. Messrs. Mitchell and Hiller describe in their testimony PECO's proposal for the sale of Intangible Transition Property and issuance of Transition Bonds, as well as PECO's planned use of the proceeds of the sale and/or issuance.

Q3. The utility must demonstrate why a particular level or amount of transition costs should be approved in the Qualified Rate Order, and why it is in the public interest that such amount should be approved within the time frame requested by the utility.

A3. Mr. Hill presents PECO's specific claim in his testimony and explains why its approval is in the public interest.

Q4. The utility should specifically address the reasons for any request for expedited treatment of the filing, including why the specific amount request should be granted prior to the final determination of stranded costs.

A4. As explained by Messrs. Hill, Mitchell and Hiller, PECO has requested expedited treatment of this filing (1) to provide its retail customers a rate decrease at the earliest possible date and (2) to take advantage of the favorable market conditions which prevail today.

B. Stranded Costs

Q1. Provide the detailed calculations which will support the Company's proposed stranded costs and Intangible Transition Charge (ITC). Include a 3.5 inch diskette with an Excel Version 5.0 copy of the macro model used to calculate the Company's claim for transition or stranded costs.

A1. Enclosed is 3.5 inch diskette with Excel version 5.0 copies of the three spreadsheets used to calculate the Company's claim for stranded costs as presented in Mr. Hill's testimony.

Q2. Provide a copy of the Company's tariffs, rate schedules and customer bills, as proposed to be revised to reflect the ITC.

A2 Exhibit 6 of PECO's Application contains the Company's proposed tariff as discussed in Mr. Xander's testimony. Mr. Xander provides sample bill calculations in Exhibit SRX-1.

Q3. Provide a copy of the corporate structure of which the Company is a part including applicable ownership percentages. Also include a flow chart of said corporate structure.

A3. Attached as Attachment FG-1 is a package of information which defines PECO Energy's corporate structure. All entities are wholly-owned by PECO Energy unless otherwise specified.

Q4. Please provide net book values as of 12/31/96 for each generating unit or plant wholly or partially owned by each utility.

A4. The requested information for 12/31/96 is not available at this time in the detail requested. We are in the process of closing the Company's books for 1996 and expect to provide the requested data by 1/31/97. The data for 12/31/95 is provided in Attachment FG-2. The total net generation plant for 12/31/96 is provided in Exhibit ABC-1.

Q5. Please provide a return-to-revenue factor (gross-up factor) for 1999.

A5. The rate of return and the revenue return level are provided in Exhibit ABC-7, page 4, and ABC-10.

Q6. Please provide a basis (i.e., methodology) and computation of each generating plant's all-in cost per kWh using the net book value amount indicated in item #4. Please pay special attention to explaining how the computation of each generating unit's all-in cost/kWh is reasonable.

A6. Detailed information concerning the costs of PECO's generation units is contained in the Exhibits to Mr. Hill and Mr. Cohn's Testimony. In order to provide an all-in bus-bar cost for each unit it would be best to utilize 1996 end of year data. As discussed, the books are being closed for year end and we expect that the data for each plant will be available by January 31, 1997. PECO would be happy to meet with appropriate parties to discuss additional analyses that might be performed.

Q7. Please provide a discount rate, such as the weighted average cost-of-capital for use in computing the net present value of lost revenues and stranded capital at each generating plant /unit.

A7. The discount rate used is discussed in Mr. Hill's testimony, page 10. The rate is derived from the cost of capital in Exhibit ABC-7, page 4.

Q8. For 1999 and each and every year that the generating unit/plant would have remained in regulated ratebase, please provide a forecast of market clearing prices for the utility's portfolio of generation assets. Please indicate the number of years that the generating unit would have remained in rate base starting in 1999. Please indicate the rated capability for the plant or unit as of 1996, and the average capacity factor for the plant/unit for the previous 5 years. Please provide the average capacity factor forecasted for the subsequent five years.

A8. Mr. Hill's testimony, Exhibits TPH-2 through TPH-4, pages 9-10, contain market-clearing prices based on three different market price studies for each generating station for each year that the plant is expected to remain active. Attached as Attachment FG-3 is a summary of the average capacity factor of each unit for the last 5 years.

Q9. Please re-compute item #8 under the assumption that oil, coal and gas prices rise to 15 year highs from 1985. Please re-compute item #8 under the assumption that natural gas prices rise to $4.00/mcf in 1999.

A9. PECO would be happy to meet with appropriate parties to discuss additional analyses that might be performed.

Q10. Please produce a graph showing stranded capital for the utility's generating portfolio on the y-axis and market clearing prices on the x-axis. Use 4 prices on the x-axis, 2 cents/kWh, 2.5 cents/kWh, 3 cents/kWh and 4 cents/kWh.

A10. PECO would be happy to meet with appropriate parties to discuss additional analyses that might be performed.

Q11. Regulatory Assets--Deferred Taxes:

a. Provide a detailed scheduled of Investment Tax Credits generated, the annual amortization, an explanation of adjustments and the unamortized balance at December 31, 1996. Provide the analysis on a vintage year basis and by plant account. Generating units, in excess of 100 MW in rated capacity, should be analyzed individually.

b. Provide a detailed schedule of state and federal Accumulated Deferred Income Taxes with respect to Depreciation and other tax timing differences. The schedule should include the annual Deferred Tax Expense. Provide the analysis on a vintage year basis and by plant account. Major generating units should be analyzed individually.

c. Please provide a schedule of when regulatory assets currently on the utility's balance sheet are to be paid. In particular provide a list of when deferred state and federal taxes are to be paid.

A11.

a. A schedule of the investment tax credits generated and the associated amortization is attached as Attachment FG-4.

b. A schedule detailing the state and federal accumulated deferred income taxes as of December 30, 1996 is attached as Attachment FG-5. The data is for 12/31/96.

c. The Company provides the annual amortization of these costs in Exhibit ABC-7.

Q12. Please provide an Operation and Maintenance expense efficiency factor. The efficiency factor should reflect the recent and projected productivity gains (or losses) of the firm. Calculations must be provided. This will represent the company's estimate for potential cost saving measures which should be utilized to be competitive in the future market structure. Explain and identify by FERC account each O&M expense that may be reduced and also each account that may not be reduced and why.

A12. Mr. Hill's testimony describes the Company's efforts to reduce O&M costs over the last six years, and Exhibit TPH-9 demonstrates that operating expenses have significantly declined in real terms on a kilowatt hour basis since 1990. Additionally, as described in Mr. Hill's testimony, for purposes of calculating stranded costs PECO has used O&M expense targets which are lower than current actual levels. The Company does not calculate expense efficiency factors as suggested by this question.

Q13 Provide an inflation factor or factors that may be applied to sales (Mwh), O&M expenses, certain stranded costs (other than net plant), fuel expenses (nuclear, gas, etc.), and regulatory assets currently included in base rates and currently outside base rates

A13. Sales growth and fuel expense escalation assumptions are addressed in Mr. Bustard's, Mr. Venkateshwara's and Mr. Hieronymus' testimony. A discussion of O&M escalation is provided in Mr. Hill's Exhibits.

Q14. Provide a methodology to designate an appropriate allocation among the company's various types of generation (i.e. nuclear, steam, etc.) of the following data for each year of the forecast period:

a. Original Cost of Plant in Service
b. Accumulated Depreciation and Amortization
c. Construction Work In Progress (CWIP)
d. Nuclear Fuel Inventory
e. Working Capital
f. Regulatory Assets
g. Accumulated Deferred Income Taxes
h. Depreciation Expense
i. Amortization Expense
j. Taxes Other than Income Taxes
k. Insurance
l. Operation Expenses
m. Maintenance Expenses
n. Fuel Expense (Gas, Coal, etc.)
o. Miscellaneous Expenses
p. Nuclear Decommissioning Expenses
q. Purchases Power - Existing Contracts
r. Federal Income Taxes

A14. Mr. Cohn discusses the allocation of costs in his testimony.

Q15. Provide a methodology to designate an appropriate allocation of the following categories to type of generation (steam, nuclear, etc.) and customer classes:

a. Return on Investment
b. Depreciation and Amortization Expense
c. Taxes Other than Income and Insurance
d. Operation and Maintenance Expenses
e. Fuel Expense
f. Miscellaneous Expense
g. Nuclear Decommissioning Expense
h. Purchased Power
I. Federal Income Taxes

A.15 Costs are not allocated on the basis of type of generation. Mr. Cohn discusses the allocation of costs in his testimony.

Q16 Sales forecast:

a. Provide a methodology to designate an appropriate allocation among the various types of generation the company's sales (Mwh) for each year of the forecast period.

b. For each year of the forecast period provide a methodology to designate an appropriate allocation of sales (Mwh) by generation type provided in response to a., above, among the customer classes.

A16. The three market price analyses discussed by Mr. Bustard project generation on an hourly basis for each generation station.

Q17. Provide the following revenue data:

a. A proof of revenues using currently effective present rates, and

b. A proof of revenues using the company's proposed rate structure.

A17. A proof of revenue using current and proposed revenues is included on Exhibit SRX - 2, to PECO Statement No. 3.

Q18. Provide a detailed explanation, including all assumptions and computations used to allocate the proposed recovery of net stranded costs (CTC and ITC) in a manner that does not shift inter-class or intra-class costs and maintains consistency with the allocation methodology for utility production plant accepted by the commission in the company's most recent base rate proceeding.

A18. An explanation of why the Company's proposed methodology does not produce intra-class or intra-class cost shifting issue is provided in Mr. Cohn's testimony, Section V and Mr. Xander's testimony, Section II.

Q19. Provide the allocation methodology for utility production plant accepted by the Commission in the company's most recent base rate proceeding in electronic format (Excel 5.0) and on paper.

A19. Exhibit ABC-11 provides the requested allocation methodology. Also enclosed is an Excel 5.0 version of the same.

C. Proceeds

Q1. Provide the specific plan of the utility for the use of the proceeds of any refinancing or sale of assets. State specifically how the proceeds for any sale or refinancing will be used by the utility. Be specific as to the amounts to be used for each specific purpose.

A1. Please see the testimony of J. Barry Mitchell.

Q2. Provide a complete accounting of any and all transition costs that are being securitized and that are associated with the utility's plan for providing employee severance, retraining, early retirement, outplacement and related services for employees who jobs are affected as a result of the restructuring of the electric industry.

A2. None at this time.

Q3. *Provide a complete plan for the use of any portion of the proceeds for the issuance of* transition bonds to provide for those activities listed in Item #2.

A3. Not applicable.

D. Applications for Qualified Rate Orders: Securitization

Q1. State the name and address of entity issuing transition bonds and whether issuer is affiliated with the public utility.

A1. As described in Mr. Mitchell's testimony, the entity issuing the bonds will be a Special-Purpose Entity which has not yet been established. The Company will provide the specific information requested as part of its Final Terms of Issuance filing required under Section 2812 (B)(9).

Q2. For the transition bonds to be issued,

a. Provide expected ratings, term structure and interest rate structure for the transition bonds, including spreads over Treasury yields for key maturities, based upon market conditions near the date of filing. Include an estimate of issuance expenses.

b. Identify the markets or specific type of investors who are expected to purchase the transition bonds.

A2. The requested information is provided, to the extent it is known, in Mr. Mitchell's testimony and Mr. Hiller's testimony as follows:

a. Expected ratings are discussed in Mr. Mitchell's testimony pp18-19.
Term structure is discussed in Mr. Hiller's testimony p 17.
Interest rate structure is discussed in Mr. Hiller's testimony p 18.
Issuance expenses are discussed in Mr. Mitchell's testimony p 10 and in Exhibit JBM-1.

b. Refer to Mr. Hiller's testimony p 13.

Q3. For the obligations to be redeemed, state the date when, and price at which, obligations are to be called or otherwise redeemed, and submit statement showing savings to be effected as a result of such redemption.

A3. Section IV of Mr. Mitchell's testimony p. 11 describes the Company's plan for use of proceeds.

Q4. Provide financial statements of the public utility dated within three months of the date of this filing. Financial statements should be set up by general ledger accounts, and not by groupings thereof. If any transactions have occurred between the date of the balance sheet and the date of this filing which have substantially affected the financial status of the public utility, a statement thereof shall be made as a footnote to the balance sheet. Include all footnotes to the financial statements.

A4. Attached, as Attachment FG-6, are PECO Energy Company Financial Statements dated September 30, 1996.

Q5. Provide a statement showing the status of the funded debt of the public utility outstanding at the date of the balance sheet referred to in Paragraph No. 4 above, and pro forma. Include name and description of obligation, interest rate, dates payable, terms, date of maturity, total principal authorized, and total principal amount outstanding.

A5. Exhibit JBM-2 contains a listing of the Company's outstanding debt and related information including interest rates, dates of maturity and total principal outstanding as of December 31, 1996, the date used to calculate refunding costs. Proforma statements of outstanding debt cannot be provided at this time because the identity of the obligation to be redeemed is not known.

Q6. Provide a statement showing the status of outstanding capital stock of the public utility as of the date of the balance sheet referred in Paragraph No. 4 above, and pro forma. Include designation of kind and class, number of shares authorized, par value per share, amount authorized, amount outstanding, amount reacquired and held in treasury, and amount pledged.

A6. Exhibit JBM-2 contains a listing of the Company's outstanding preferred and common stock including the requested information as of December 31, 1996, the date used to calculate refunding costs. Pro forma statements of outstanding debt cannot be provided at this time because the identify of the obligations to be redeemed is now known .

Q7. Accounting entries:

a. Provide a statement showing, in journal entry form, all charges and credits to be made on the books of account of the public utility as a result of the proposed sale of assets and redemption of securities.

b. Provide a detailed explanation of each journal entry and the effect upon the financial accounting books of the utility and its affiliates.

c. Provide a detailed analysis of the transactions as a sale of assets for book purposes.

A7.a.b.c. Exhibit 2 and 3 to PECO's Application contains proposed journal entries reflecting the charges and credits to be made on the Company's books. These journal entries are described in Mr. Gillen's and Mr. Hill's testimony.

Q8. Provide an outline of each of the contracts to be entered into with respect to the proposed sale of assets.

A8. The Company will provide copies of relevant contract documents as part of its Final Terms of Issuance filing required under Section 2812 (B)(9).

Q9. Provide a pro forma projection of Sources and Uses of Funds for a period of at least three years.

A9. The Company has no publicly available pro forma projection of sources and uses of funds for the next three years.

Q10. Provide a statement showing the present and pro forma capital structure.

A10. As discussed in Mr. Mitchell's testimony, the Company expects to maintain its existing capital structure on a pro rata basis which is set forth in Mr. Mitchell's testimony pp 12 and 13.

Q11. Taxes:

a. Provide a description of the tax effects of the securitization and transition bond process. Include detailed explanations for each segment of the process as defined by the book journal entries. Address the issue of the transactions resulting in a sale of assets for tax purposes.

b. Explain all current state and federal tax laws, regulations, rulings, memorandums or communications which have a bearing upon the proposed transactions.

c. Explain, in detail, any rulings or other determinations which the utility should or must seek from taxing authorities in connection with the proposed transactions.

A11. a. The Company believes the securitization transition will not be treated as a sale for deferral income tax purposes. As a result, there would be no gain or loss from the Sale of Intangible Transition Property or the issuance of Transition Bonds. Rather, collection of the ITC from customers would constitute taxable income. If, however, the tax treatment of the transaction is ultimately determined to be a sale for federal income tax purposes, the securitization transaction would result in income taxes being currently payable. The Company believes state income tax treatment would follow the federal income tax treatment.

b. The legal documents ultimately prepared as part of the securitization process, and as part of the issuance of transition bonds, will determine which tax laws, regulations, rulings, etc. are applicable.

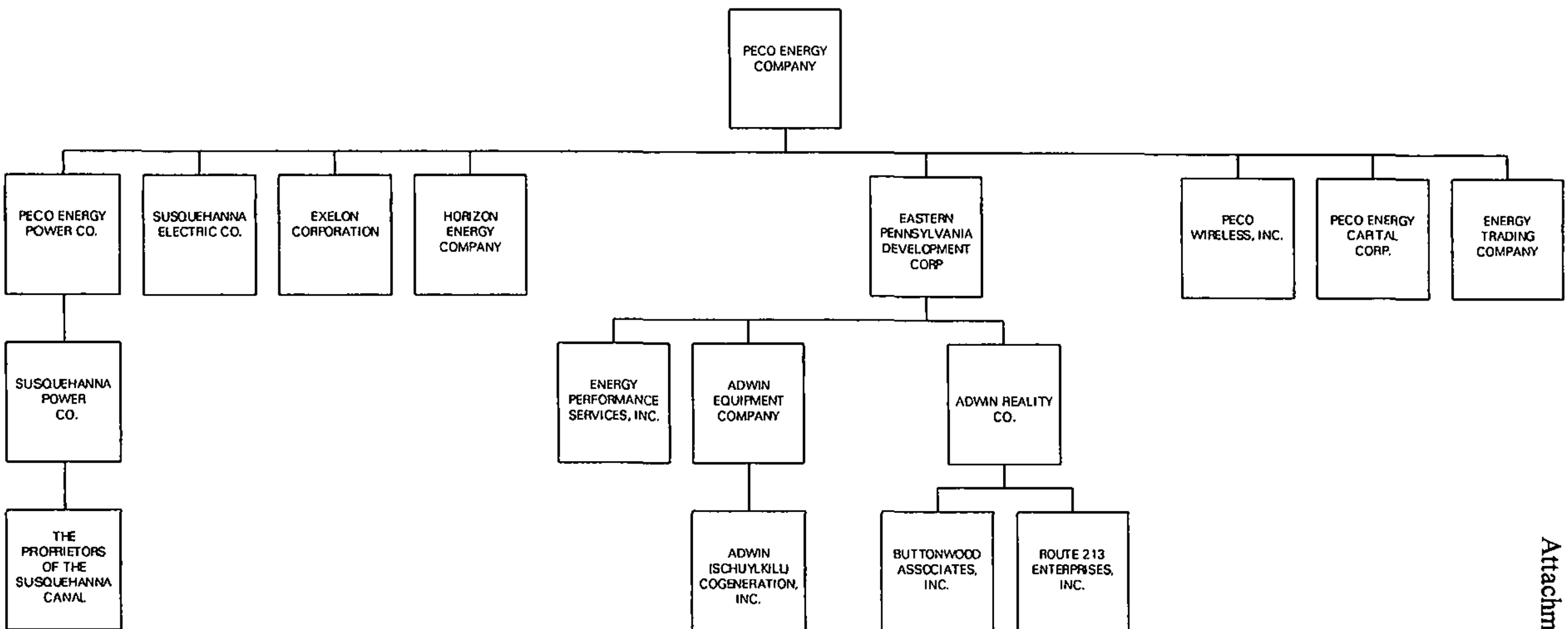
c. The Company is in the process, of preparing a revenue ruling request to the IRS relating to the proposed tax treatment of securitization.

Q12. Describe and quantify the mitigation efforts undertaken for each plant and regulatory asset for which stranded costs are claimed.

A12. In his testimony, Mr. Hill describes in detail the steps taken by the Company to mitigate stranded costs.

Revised: 1/16/97

PECO ENERGY COMPANY



Attachment FG-1

Revised as of 1/16/97

PECO ENERGY COMPANY
CORPORATE STRUCTURE*

1. **PECO Energy Company** - (PECO Energy)
   PA Corporation

2. **PECO Energy Power Company** - (PEPCO)
   PA Corporation
   Registered holding company
   Owns Pennsylvania portion of Conowingo project
   No employees

3. **Susquehanna Power Company** - (SPCO)
   Maryland Corporation
   Subsidiary of PEPCO
   Owns Maryland part of Conowingo project
   No employees

4. **Susquehanna Electric Company** - (SECO)
   Maryland Corporation
   Operates the Conowingo project, sells bulk power only to COPCO and PECO Energy
   Does not serve the public

5. **PECO Wireless, Inc.**
   Pennsylvania Corporation
   Owns 49% of AT&T Wireless PCS of Philadelphia, LLC, a Delaware limited liability company, formed to offer personal communication services (PCS) in the Philadelphia Major Trading Area (MTA).

6. **The Proprietors of the Susquehanna Canal**- (inactive)
   Maryland Corporation
   Subsidiary of SPCO
   The company was incorporated in 1783 and was acquired in connection with the development of the Conowingo Project. It is an inactive company, owning no properties and conducting no business activities.
   No employees

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* Unless otherwise noted, companies are first-tier subsidiaries of PECO Energy Company.

53588
53588

7. **Horizon Energy Company (formerly known as PECO Gas Supply Company)**
PA Corporation
Participates in East Coast Natural Gas Cooperative, L.L.C., a Delaware limited liability company which facilitates the coordinated use of certain natural gas capacity, storage, transportation and supply assets in order to improve service reliability and efficiency. Also operates as an unregulated marketer of natural gas, on and off-system, under its name and the registered mark Horizon Energy.

8. **PECO Energy Capital Corp.**
Delaware Corporation
General Partner of PECO Energy Capital, L.P., a Delaware limited partnership the sole purpose of which is to issue cumulative monthly income preferred securities.
No employees

9. **Eastern Pennsylvania Development Company** - (EPDC)
PA Corporation
Intended to develop electrical uses in eastern Pennsylvania
No employees

10. **Energy Performance Services, Inc.** (EPS)
PA Corporation
Energy services company, formed in 1994, includes Heatac ground source heating and cooling business
96% owned subsidiary of EPDC
2 outside shareholders

11. **Exelon Corporation**
PA Corporation
Energy services company formed, in December 1996, providing operation, management and consulting services for owners and operators of electric or energy generation equipment and plants

12. **Adwin Equipment Company** - (AEC)
PA Corporation
Subsidiary of EPDC
Leases equipment
Cogeneration activity
No employees

13. **Adwin (Schuylkill) Cogeneration, Inc.**
PA Corporation
Subsidiary of AEC
Special purpose corporation which holds a 33.3% interest in the Grays Ferry Cogeneration Project.
No employees

14. **Adwin Realty Company** - (ARC)
PA Corporation
Subsidiary of EPDC
Owns and manages real estate
No employees

15. **Buttonwood Associates, Inc.**
Delaware Corporation
Subsidiary of ARC
Formed as a corporate vehicle for the development of townhouses on a parcel of ground outside of Elkton, MD.
No employees

16. **Route 213 Enterprises, Inc.**
Delaware Corporation
Wholly owned subsidiary of ARC (as of June 1996)
Formed as a corporate vehicle for the development of a two acre parcel of ground outside of Elkton, Maryland.
No employees

17. **Energy Trading Company**
Delaware Corporation
Formed in December 1996, owns 50% of Barter One, LLC, a Delaware limited liability company, formed to develop and market electronic commerce software to facilitate barter trading via the Internet.
No employees

Note:

Adwin Investment Company - (AIC)
(Dissolved as of July 31, 1996)
Subsidiary of EPDC
Delaware holding corporation
Holds investment assets of Adwin companies to minimize PA tax.
No employees

Blue Spruce Associates, Inc.
(Ownership interest transferred to Franklin Associates as of June 1996)
Delaware Corporation
Owned by AdFrank I Partnership, which is owned 52% by ARC and 48% by Franklin Associates (outside partners). Formed as a corporate vehicle for the development of a 41.3 acre parcel of ground outside of Elkton, Maryland.
No employees

Eastern Pennsylvania Exploration Company - (EPEC)
(Company is winding up and will be dissolved once a tax clearance certificate is obtained)
PA Corporation
Locates and develops natural gas sources
No employees

PECO ENERGY COMPANY SUBSIDIARIES

Eastern Pennsylvania Development Co.

Subsidiaries: Adwin Equipment Company
Adwin Realty Company
Adwin (Schuylkill) Cogeneration, Inc.
Buttonwood Associates, Inc.
Energy Performance Services, Inc.
Route 213 Enterprises, Inc.

Exelon Corporation

PECO Energy Power Company

Subsidiaries: Susquehanna Power Company
The Proprietors of the Susquehanna Canal (Inactive)

PECO Energy Capital Corp.

PECO Gas Supply Company

PECO Wireless, Inc.

Susquehanna Electric Company

Energy Trading Company

PECO Energy's Subsidiaries

Adwin Investment Company
1105 N. Market Street
Suite 1300
P.O. Box 8985
Wilmington, DE 19899-8985
Tax I.D. No. 23-0332946
(Dissolved as of 7/31/96)

Adwin Equipment Company
2301 Market Street
Philadelphia, PA 19103
Tax I.D. No. 23-1706178

Adwin Realty Company
2301 Market Street
Philadelphia, PA 19103
Tax I.D. No. 23-1706179

Adwin (Schuylkill) Cogeneration,, Inc.
2301 Market Street
Philadelphia, PA 19103
Tax I.D. No. 23-2829266

Blue Spruce Associates, Inc.
c/o Adwin Realty Company
300 Stevens Drive
Lester, PA 19113
Tax I.D. No. 51-0323766
(Ownership interest transferred as of June 1996)

Buttonwood Associates, Inc.
c/o Corporation Trust Company
1209 Orange Street
Wilmington, DE 19801
Tax I.D. No. 51-0323767

Conowingo Power Company
213 North Street
Elkton, MD 21921
Tax I.D. No. 23-0280040
Sold 6/19/95

Eastern Pennsylvania Development Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101-8699
Tax I.D. No. 23-1706184

Eastern Pennsylvania Exploration Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101-8699
Tax I.D. No. 23-2039821
(Winding Up)

Energy Performance Services, Inc.
The Commons
2003 Renaissance Blvd.
King of Prussia, PA 19406
Tax I.D. No. 23-2750899

Energy Trading Company
c/o Corporation Service Company
1013 Centre Road
Wilmington, Delaware 19805
Tax I.D. No. 23-2867864

Exelon Corporation
955 Chesterbrook Boulevard
53A-2
Wayne, PA 19087-5691
Tax I.D. No. 23-2866286

Horizon Energy Company
300 Front Street
W. Conshohocken, PA 19428
Tax I.D. No. 23-2798733

PECO Energy Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101-8699
Tax I.D. No. 23-0970240

PECO Energy Capital Corp.
Suite 350-F
1013 Centre Road
Wilmington, DE 19805
Tax I.D. No. 51-0355321

PECO Power Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101-8699
Tax I.D. No. 23-0970740

PECO Wireless, Inc.
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101-8699
Tax I.D. No. 23- 2838358

The Proprietor's of the
Susquehanna Canal
c/o Susquehanna Power Company
2569 Shures Landing Road
Darlington, MD 21034-1503
Tax I.D. No. 23-1624948

Route 213 Enterprises, Inc.
c/o Corporation Trust Company
1209 Orange Street
Wilmington, DE 19801
Tax I.D. No. 51- 0323768

Susquehanna Power Company
2569 Shures Landing Road
Darlington, MD 21034-1503
Tax I.D. No. 23-1139830

Susquehanna Electric Company
2569 Shures Landing Road
Darlington, MD 21034-1503
Tax I.D. No. 52-0503520

PECO ENERGY COMPANY
PROVISION FOR DEPRECIATION
CLASS OF SERVICE: ELECTRIC
1/ 1/96 - 12/31/96

Attachment FG-2

ACCRUAL - NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
INTANGIBLE PLANT			-PEACH BOTTOM 2 + 3			66				
66	3031	26345130.83	0.0	0.0	0.0	0.0	0.0	0.0	0	0
66	TOTAL	26345130.83	0.0	0.0	0.0	0.0	0.0	0.0		
INTANGIBLE PLANT			-PEACH BOTTOM CF			68				
68	3030	9497194.08	0.0	0.0	0.0	0.0	0.0	0.0	0	0
68	TOTAL	9497194.08	0.0	0.0	0.0	0.0	0.0	0.0		
INTANGIBLE PLANT			-LIMERICK 100% COM			99				
99	3030	19382481.15	0.0	0.0	0.0	0.0	0.0	0.0	0	0
99	TOTAL	19382481.15	0.0	0.0	0.0	0.0	0.0	0.0		
INTANGIBLE PLANT			-601			601				
601	3020	162934.12	0.0	0.0	0.0	0.0	0.0	0.0	0	0
601	TOTAL	162934.12	0.0	0.0	0.0	0.0	0.0	0.0		
INTANGIBLE PLANT			- TOTAL OF ALL STATIONS							
FUN.	3020	162934.12	0.0	0.0	0.0	0.0	0.0	0.0		
FUN.	3030	28879675.23	0.0	0.0	0.0	0.0	0.0	0.0		
FUN.	3031	26345130.83	0.0	0.0	0.0	0.0	0.0	0.0		
FUN.	TOTAL	55387740.18	0.0	0.0	0.0	0.0	0.0	0.0		
STEAM PRODUCTION			-SCHUYKILL (1,3)			1				
1	3101	295740.65	0.0	0.0	0.0	0.0	0.0	0.0	0	0
1	3110	7000332.35	7000332.35	0.0	100.000	0.0	0.0	0.0	82SA	1992
1	3120	20336238.80	20281551.53	54687.27	100.000	54687.27	0.0	54687.27	50RB	1992
1	3140	8619191.20	8614003.33	5187.87	100.000	5187.87	0.0	5187.87	74LB	1992
1	3150	5977014.26	5976178.96	835.30	100.000	835.30	0.0	835.30	73L0	1992
1	3160	728653.41	706856.61	21796.80	100.000	21796.80	0.0	21796.80	54RB	1992
1	TOTAL	42957170.67	42578922.78	82507.24	100.000	82507.24	0.0	82507.24		
STEAM PRODUCTION			-EDDYSTONE 1 + 2			6				
6	3101	2408255.54	0.0	0.0	0.0	0.0	0.0	0.0	0	0
6	3102	5126.40	0.0	0.0	0.0	0.0	0.0	0.0	0	0
6	3110	72953447.70	46160728.68	26792719.02	7.145	1914339.77	0.0	1914339.77	82SA	2010
6	3120	268396629.27	141120284.51	127276344.76	7.407	9427358.86	0.0	9427358.86	50RB	2010
6	3140	73310094.56	33786738.99	39523355.57	7.190	2841729.27	0.0	2841729.27	74LB	2010
6	3150	26500055.98	18786793.48	7713262.50	7.388	569855.83	0.0	569855.83	73L0	2010
6	3160	4882312.89	2997091.45	1885221.44	7.402	139544.09	0.0	139544.09	54RB	2010
6	TOTAL	448455922.34	242851637.11	203190903.29	7.329	14892827.82	0.0	14892827.82		
STEAM PRODUCTION			-DELAWARE (7,8)			9				
9	3101	1353562.84	0.0	0.0	0.0	0.0	0.0	0.0	0	0
9	3110	16312070.33	16329199.70	-17129.37	100.000	-17129.37	0.0	-17129.37	82SA	1990
9	3120	28028154.20	26230282.23	1797871.97	100.000	1797871.97	0.0	1797871.97	50RB	1990
9	3140	11673660.39	11632457.71	41202.68	100.000	41202.68	0.0	41202.68	74LB	1990
9	3150	10256073.16	10252528.92	3544.24	100.000	3544.24	0.0	3544.24	73L0	1990
9	3160	2265382.90	2109840.44	155542.46	100.000	155542.46	0.0	155542.46	54RB	1990
9	TOTAL	69888903.82	66554309.00	1981031.98	100.000	1981031.98	0.0	1981031.98		

PECO ENERGY COMPANY
PROVISION FOR DEPRECIATION
CLASS OF SERVICE: ELECTRIC
1/ 1/96 - 12/31/96

1/ 1/96 ACCRUAL RB-16
02/14/96 09:48:44

ACCRUAL - NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
STEAM PRODUCTION			-RICHMOND (9)			10				
10	3120	0.0	256994.76	-256994.76	100.000	-256994.76	0.0	-256994.76	50RB	1985
10	TOTAL	0.0	256994.76	-256994.76	100.000	-256994.76	0.0	-256994.76		
STEAM PRODUCTION			-CONEMAUGH (1,2)			15				
15	3101	494481.77	0.0	0.0	0.0	0.0	0.0	0.0	0	0
15	3110	17007541.82	8257922.48	8749619.34	9.673	846350.68	0.0	846350.68	82SA	2006
15	3120	119158326.82	33053975.59	86104351.23	9.829	8463196.68	0.0	8463196.68	50RB	2006
15	3140	22051224.48	12347714.83	9703509.65	9.757	946771.44	0.0	946771.44	74LB	2006
15	3150	4273225.08	2856627.49	1416597.59	10.017	141900.58	0.0	141900.58	73L0	2006
15	3160	1050311.81	798953.00	251358.81	9.875	24821.68	0.0	24821.68	54RB	2006
15	TOTAL	164035111.78	57315193.39	106225436.62	9.812	10423041.06	0.0	10423041.06		
STEAM PRODUCTION			-KEYSTONE (1,2)			17				
17	3101	894387.86	0.0	0.0	0.0	0.0	0.0	0.0	0	0
17	3110	15554246.30	8580369.24	6973877.06	13.482	940218.11	0.0	940218.11	82SA	2003
17	3120	66648962.95	30731322.20	35917640.75	13.702	4921435.14	0.0	4921435.14	50RB	2003
17	3140	21707252.29	10960105.67	10747146.62	13.525	1453551.58	0.0	1453551.58	74LB	2003
17	3150	3710303.44	2654036.58	1056266.86	13.801	145775.39	0.0	145775.39	73L0	2003
17	3160	630541.43	149630.08	480911.35	13.646	65625.16	0.0	65625.16	54RB	2003
17	TOTAL	109145694.27	53075463.77	55175842.64	13.641	7526605.38	0.0	7526605.38		
STEAM PRODUCTION			-EDDYSTONE 3			71				
71	3120	50146005.73	30115289.12	20030716.61	7.927	1587834.91	0.0	1587834.91	50RB	2009
71	3140	22611738.83	10338506.97	12273231.86	7.633	936815.79	0.0	936815.79	74LB	2009
71	3150	2198629.70	1357417.34	841212.36	7.909	66531.49	0.0	66531.49	73L0	2009
71	TOTAL	74956374.26	41811213.43	33145160.83	7.818	2591182.19	0.0	2591182.19		
STEAM PRODUCTION			-EDDYSTONE 4			72				
72	3120	52074317.93	29096614.52	22977703.41	6.945	1595801.50	0.0	1595801.50	50RB	2011
72	3140	22268210.03	10449491.18	11818718.85	6.692	790908.67	0.0	790908.67	74LB	2011
72	3150	2233491.48	1786198.80	447292.68	6.936	31024.22	0.0	31024.22	73L0	2011
72	TOTAL	76576019.44	41332304.50	35243714.94	6.860	2417734.39	0.0	2417734.39		
STEAM PRODUCTION			-EDDYSTONE CF			73				
73	3110	53344505.65	29474282.92	23870222.73	6.677	1593814.77	0.0	1593814.77	82SA	2011
73	3120	68276881.13	25338155.51	42938725.62	6.853	2942590.87	0.0	2942590.87	50RB	2011
73	3140	10518016.53	5947663.04	4570353.49	6.749	308453.16	0.0	308453.16	74LB	2011
73	3150	22493546.77	12754274.89	9739271.88	6.940	675905.47	0.0	675905.47	73L0	2011
73	3160	5594655.62	1980238.99	3614416.63	6.786	245274.31	0.0	245274.31	54RB	2011
73	TOTAL	160227605.70	75494615.35	84732990.35	6.805	5766038.58	0.0	5766038.58		
STEAM PRODUCTION			-CROMBY 1 - COAL UNIT			81				
81	3110	18372831.59	13546091.71	4826739.88	11.938	576216.21	0.0	576216.21	82SA	2004
81	3120	70050222.48	47755612.85	22294609.63	12.252	2731535.57	0.0	2731535.57	50RB	2004
81	3140	12095558.77	6592788.55	5502770.22	12.105	666110.34	0.0	666110.34	74LB	2004
81	3150	7490270.54	5753326.88	1736943.66	12.217	212202.41	0.0	212202.41	73L0	2004
81	3160	781703.69	560395.71	221307.98	12.199	26997.36	0.0	26997.36	54RB	2004
81	TOTAL	108790587.07	74208215.70	34582371.37	12.183	4213061.89	0.0	4213061.89		

PECO ENERGY COMPANY
PROVISION FOR DEPRECIATION
CLASS OF SERVICE: ELECTRIC
1/ 1/96 - 12/31/96

1/ 1/96 ACCRUAL RB-17
02/14/96 09:48:44

A-4d

ACCRUAL = NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
STEAM PRODUCTION			-CROMBY 2 - OIL UNIT			82				
82	3110	75537.51	75537.51	0.0	100.000	0.0	0.0	0.0	82SA	1990
82	3120	34949771.70	19824782.72	15124988.98	100.000	15124988.98	0.0	15124988.98	50RB	1990
82	3140	12688057.02	10768836.66	1919220.36	100.000	1919220.36	0.0	1919220.36	74LB	1990
82	3150	2252107.75	2224131.76	27975.99	100.000	27975.99	0.0	27975.99	73L0	1990
82	3160	561241.15	425071.45	136169.70	100.000	136169.70	0.0	136169.70	54RB	1990
82	TOTAL	50526715.13	33318360.10	17208355.03	100.000	17208355.03	0.0	17208355.03		
STEAM PRODUCTION			-CROMBY CF			83				
83	3101	55349.54	0.0	0.0	0.0	0.0	0.0	0.0	0	0
83	3110	19992951.91	17127898.58	2865053.33	12.040	344952.42	0.0	344952.42	82SA	2004
83	3120	5797451.73	3464471.80	2332979.93	12.184	284250.27	0.0	284250.27	50RB	2004
83	3140	1170182.75	829471.99	340710.76	12.148	41389.54	0.0	41389.54	74LB	2004
83	3150	2635996.95	1738040.73	897956.22	12.224	109766.17	0.0	109766.17	73L0	2004
83	3160	2261857.75	1187116.51	1074741.24	12.209	131215.16	0.0	131215.16	54RB	2004
83	TOTAL	31913790.63	24346999.61	7511441.48	12.136	911573.56	0.0	911573.56		
STEAM PRODUCTION			-ALLIED CHEMICAL			305				
305	3110	129720.15	67447.81	62272.34	7.060	4396.43	0.0	4396.43	82SA	2010
305	3150	220874.85	133973.64	86901.21	7.325	6365.51	0.0	6365.51	73L0	2010
305	TOTAL	350595.00	201421.45	149173.55	7.214	10761.94	0.0	10761.94		
STEAM PRODUCTION			-ESSEX CHEMICAL			306				
306	3110	1354205.47	571342.25	782863.22	7.042	55129.23	0.0	55129.23	82SA	2010
306	3150	795327.04	657023.38	138303.66	7.303	10100.32	0.0	10100.32	73L0	2010
306	TOTAL	2149532.51	1228365.63	921166.88	7.081	65229.55	0.0	65229.55		
STEAM PRODUCTION			-TOOLS + WORK EQUIPMENT			372				
372	3120	809718.01	676003.74	133714.27	14.495	19381.88	0.0	19381.88	21LB	0
372	TOTAL	809718.01	676003.74	133714.27	14.495	19381.88	0.0	19381.88		
STEAM PRODUCTION			-SAMAC			503				
503	3150	475908.29	-345593.86	821502.15	100.000	821502.15	0.0	821502.15	38SB	1992
503	TOTAL	475908.29	-345593.86	821502.15	100.000	821502.15	0.0	821502.15		
STEAM PRODUCTION			- TOTAL OF ALL STATIONS							
FUN.	3101	5501778.20	0.0	0.0	0.0	0.0	0.0	0.0		
FUN.	3102	5126.40	0.0	0.0	0.0	0.0	0.0	0.0		
FUN.	3110	222097390.78	147191153.23	74906237.55	8.355	6258288.25	0.0	6258288.25		
FUN.	3120	784672680.75	407945341.08	376727339.67	12.926	48693939.14	0.0	48693939.14		
FUN.	3140	218713186.85	122267778.92	96445407.93	10.318	9951340.70	0.0	9951340.70		
FUN.	3150	91512825.29	66584958.99	24927866.30	11.326	2823285.07	0.0	2823285.07		
FUN.	3160	18756660.65	10915194.24	7841466.41	12.077	946986.72	0.0	946986.72		
FUN.	TOTAL	1341259648.92	754904426.46	580848317.86	11.823	68673839.88	0.0	68673839.88		
NUCLEAR PRODUCTION			-MERRILL CREEK			2				
2	3201	95360.00	0.0	0.0	0.0	0.0	0.0	0.0	0	0
2	3210	904383.09	108565.41	795817.68	2.937	23373.17	0.0	23373.17	80S2	2030
2	3250	4154.20	59.65	4094.55	2.932	120.05	0.0	120.05	88R3	2030
2	TOTAL	1003897.29	108625.06	799912.23	2.937	23493.22	0.0	23493.22		

PECO ENERGY COMPANY
PROVISION FOR DEPRECIATION
CLASS OF SERVICE: ELECTRIC
1/ 1/96 - 12/31/96

1/ 1/96 ACCRUAL RB-18
02/14/96 09:48:44

ACCRUAL = NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
NUCLEAR PRODUCTION			-BRADSHAW RESERVOIR			4				
4	3201	1659385.87	0.0	0.0	0.0	0.0	0.0	0.0	0	0
4	3202	679183.10	0.0	0.0	0.0	0.0	0.0	0.0	0	0
4	3210	84921918.20	2099900.27	82822017.93	3.030	2509507.14	0.0	2509507.14	80S2	2029
4	TOTAL	87260487.17	2099900.27	82822017.93	3.030	2509507.14	0.0	2509507.14		
NUCLEAR PRODUCTION			-SALEM I			61				
61	3210	60506158.00	23731726.93	36774431.07	4.939	1816289.15	0.0	1816289.15	80S2	2016
61	3220	190035764.18	77527176.71	112508587.47	5.626	6329733.13	0.0	6329733.13	41SB	2016
61	3230	54563058.20	18974197.17	35588861.03	5.038	1792966.82	0.0	1792966.82	72L2	2016
61	3240	71190710.03	26409362.21	44781347.82	4.934	2209511.70	0.0	2209511.70	98SB	2016
61	3250	7915335.40	3977896.68	3937438.72	4.939	194470.10	0.0	194470.10	88R3	2016
61	TOTAL	384211025.81	150620359.70	233590666.11	5.284	12342970.90	0.0	12342970.90		
NUCLEAR PRODUCTION			-SALEM 2			62				
62	3210	69394336.74	21626269.53	47768067.21	4.135	1975209.58	0.0	1975209.58	80S2	2020
62	3220	221157842.06	74096256.08	147061585.98	4.797	7054544.28	0.0	7054544.28	41SB	2020
62	3230	56272460.83	1065055.48	55207405.35	4.226	2333064.95	0.0	2333064.95	72L2	2020
62	3240	85553960.14	24905712.17	60648247.97	4.133	2506592.09	0.0	2506592.09	98SB	2020
62	3250	6071411.44	2647493.25	3423918.21	4.137	141647.50	0.0	141647.50	88R3	2020
62	TOTAL	438450011.21	124340786.49	314109224.72	4.461	14011058.40	0.0	14011058.40		
NUCLEAR PRODUCTION			-SALEM CF			63				
63	3201	75625.48	0.0	0.0	0.0	0.0	0.0	0.0	0	0
63	3210	133297993.05	51548790.53	81749202.52	4.150	3392591.90	0.0	3392591.90	80S2	2020
63	3220	55544606.48	22764130.83	32780475.65	4.957	1624928.18	0.0	1624928.18	41SB	2020
63	3230	46539784.88	18342860.80	28196924.08	4.289	1209366.07	0.0	1209366.07	72L2	2020
63	3240	96998269.45	18039807.76	78958461.69	4.114	3248351.11	0.0	3248351.11	98SB	2020
63	3250	27816224.15	6787812.99	21028411.16	4.123	867001.39	0.0	867001.39	88R3	2020
63	TOTAL	360272503.49	117483402.91	242713475.10	4.261	10342238.65	0.0	10342238.65		
NUCLEAR PRODUCTION			-PEACH BOTTOM 2 + 3			66				
66	3201	244878.92	0.0	0.0	0.0	0.0	0.0	0.0	0	0
66	3202	68366.28	0.0	0.0	0.0	0.0	0.0	0.0	0	0
66	3210	141973029.22	69080111.52	72892917.70	5.490	4001821.18	0.0	4001821.18	80S2	2014
66	3220	388339036.33	149422634.49	238916401.84	6.070	14502225.59	0.0	14502225.59	41SB	2014
66	3230	110610074.60	41174496.90	69435577.70	5.553	3855757.63	0.0	3855757.63	72L2	2014
66	3240	57031823.72	24640025.11	32391798.61	5.480	1775070.56	0.0	1775070.56	98SB	2014
66	3250	36554681.08	12231514.13	24323166.95	5.462	1328531.38	0.0	1328531.38	88R3	2014
66	TOTAL	734821890.15	296548782.15	437959862.80	5.814	25463406.34	0.0	25463406.34		
NUCLEAR PRODUCTION			-LIMERICK # 1			91				
91	3210	477849238.04	120487158.49	357362079.55	3.494	12486231.06	0.0	12486231.06	80S2	2024
91	3220	1520109656.35	391227345.93	1128882310.42	4.089	46159997.67	0.0	46159997.67	41SB	2024
91	3230	254618731.53	68158127.96	186460603.57	3.592	6697664.88	0.0	6697664.88	72L2	2024
91	3240	302370044.29	76487893.82	225882150.47	3.496	7896839.98	0.0	7896839.98	98SB	2024
91	3250	111334622.68	28388923.63	82945699.05	3.494	2898122.72	0.0	2898122.72	88R3	2024
91	TOTAL	2666282292.89	684749449.83	1981532843.06	3.842	76138856.31	0.0	76138856.31		
NUCLEAR PRODUCTION			-LIMERICK # 2			92				
92	3210	434673448.18	61181218.71	373492229.47	3.020	11279465.33	0.0	11279465.33	80S2	2029

PECO ENERGY COMPANY
PROVISION FOR DEPRECIATION
CLASS OF SERVICE: ELECTRIC
1/ 1/96 - 12/31/96

A-4e

ACCRUAL - NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
92	3220	1702962015.09	277957104.53	1425004910.56	3.490	49732671.38	0.0	49732671.38	41S8	2029
92	3230	304061890.67	59355280.25	244706610.42	3.100	7585904.92	0.0	7585904.92	72L2	2029
92	3240	307996607.62	45434687.90	262561919.72	3.023	7937246.83	0.0	7937246.83	98S8	2029
92	3250	89162813.41	15280895.15	73881918.26	3.024	2234189.21	0.0	2234189.21	88R3	2029
92	TOTAL	2838856774.97	459209186.54	2379647588.43	3.310	78769477.67	0.0	78769477.67		
NUCLEAR PRODUCTION		-LIMERICK 100% COM				99				
99	3201	7894356.64	0.0	0.0	0.0	0.0	0.0	0.0	0	0
99	3202	9147.60	0.0	0.0	0.0	0.0	0.0	0.0	0	0
99	3210	526458968.26	108168707.61	418290260.65	3.000	12548707.82	0.0	12548707.82	80S2	2029
99	3220	385207821.24	93051628.34	292156192.90	3.718	10862367.25	0.0	10862367.25	41S8	2029
99	3230	37267411.27	9427253.64	27840157.63	3.117	867777.71	0.0	867777.71	72L2	2029
99	3240	183270567.14	42347991.99	140922575.15	2.998	4224858.80	0.0	4224858.80	98S8	2029
99	3250	112078924.98	22650507.02	89428417.96	2.992	2675698.27	0.0	2675698.27	88R3	2029
99	TOTAL	1252187197.13	275646088.60	968637604.29	3.219	31179409.85	0.0	31179409.85		
NUCLEAR PRODUCTION		-CHESTERBROOK				301				
301	3210	3545612.65	228569.28	3317043.37	1.342	44514.72	0.0	44514.72	80S2	0
301	3250	3684459.03	217070.00	3467389.03	1.156	40083.02	0.0	40083.02	88R3	0
301	TOTAL	7230071.68	445639.28	6784432.40	1.247	84597.74	0.0	84597.74		
NUCLEAR PRODUCTION		-NUCLEAR EOF/NC				307				
307	3210	1859412.01	221162.63	1638249.38	3.016	49409.60	0.0	49409.60	80S2	2029
307	3250	440947.24	42189.81	398757.43	3.019	12038.49	0.0	12038.49	88R3	2029
307	TOTAL	2300359.25	263352.44	2037006.81	3.017	61448.09	0.0	61448.09		
NUCLEAR PRODUCTION		-NE COAL STORAGE				320				
320	3250	520297.25	10793.30	509503.95	1.178	6001.96	0.0	6001.96	88R3	0
320	TOTAL	520297.25	10793.30	509503.95	1.178	6001.96	0.0	6001.96		
NUCLEAR PRODUCTION		-OREGON SHOPS - NUCLEAR TOOLS				331				
331	3250	540198.50	27316.21	512882.29	1.203	6169.97	0.0	6169.97	88R3	0
331	TOTAL	540198.50	27316.21	512882.29	1.203	6169.97	0.0	6169.97		
NUCLEAR PRODUCTION		-PEACH BOTTOM TRAINING CENTER				363				
363	3210	470963.19	74469.19	396494.00	5.533	21938.01	0.0	21938.01	80S2	2014
363	3250	8104.45	1593.32	6511.13	5.434	353.81	0.0	353.81	88R3	2014
363	TOTAL	479067.64	76062.51	403005.13	5.531	22291.82	0.0	22291.82		
NUCLEAR PRODUCTION		-NUCLEAR INFORMATION CENTER				365				
365	3201	278944.69	0.0	0.0	0.0	0.0	0.0	0.0	0	0
365	3210	572042.01	90036.61	482005.40	3.061	14754.19	0.0	14754.19	80S2	2029
365	3250	569968.34	68004.99	501963.35	3.030	15209.49	0.0	15209.49	88R3	2029
365	TOTAL	1420955.04	158041.60	983968.75	3.045	29963.68	0.0	29963.68		
NUCLEAR PRODUCTION		-NUCLEAR TRAINING CENTER				385				
385	3201	400911.51	0.0	0.0	0.0	0.0	0.0	0.0	0	0
385	3210	5015177.22	797139.21	4218038.01	3.120	131602.79	0.0	131602.79	80S2	2028
385	3250	981830.54	145794.15	836036.39	3.112	26017.45	0.0	26017.45	88R3	2028
385	TOTAL	6397919.27	942933.36	5054074.40	3.119	157620.24	0.0	157620.24		

PECO ENERGY COMPANY
PROVISION FOR DEPRECIATION
CLASS OF SERVICE: ELECTRIC
1/ 1/96 - 12/31/96

ACCRUAL - NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
NUCLEAR PRODUCTION		- TOTAL OF ALL STATIONS								
FUN.	3201	10649463.11	0.0	0.0	0.0	0.0	0.0	0.0		
FUN.	3202	756696.98	0.0	0.0	0.0	0.0	0.0	0.0		
FUN.	3210	1961442679.86	459443825.92	1481998853.94	3.394	50295415.64	0.0	50295415.64		
FUN.	3220	4463356741.73	1086046276.91	3377310464.82	4.035	136266467.48	0.0	136266467.48		
FUN.	3230	863933411.98	216497272.20	647436139.78	3.760	24342502.98	0.0	24342502.98		
FUN.	3240	1104411982.39	258265480.96	846146501.43	3.522	29798471.07	0.0	29798471.07		
FUN.	3250	397683972.69	92477864.26	305206108.43	3.422	10445654.81	0.0	10445654.81		
FUN.	TOTAL	8782234948.74	2112730720.25	6658098068.40	3.772	251148511.98	0.0	251148511.98		
HYDRAULIC PRODUCTION		-MUDDY RUN (1,2,3,4,5,6,7,8)				19				
19	3301	812413.61	0.0	0.0	0.0	0.0	0.0	0.0	0	0
19	3302	9364.51	0.0	0.0	0.0	0.0	0.0	0.0	0	0
19	3304	599044.51	0.0	0.0	0.0	0.0	0.0	0.0	0	0
19	3311	12428586.66	5625800.42	6802786.24	5.762	391976.54	0.0	391976.54	57R4	2014
19	3312	128175.89	57309.90	70865.99	5.765	4085.42	0.0	4085.42	57R4	2014
19	3313	4921061.26	1706021.43	3215039.83	5.525	177630.95	0.0	177630.95	57R4	2014
19	3321	33575933.36	13977444.78	19598488.58	5.622	1101827.03	0.0	1101827.03	73L3	2014
19	3323	864028.70	351651.32	512377.38	5.624	28816.10	0.0	28816.10	73L3	2014
19	3330	27829946.40	12184768.40	15645178.00	5.917	925725.18	0.0	925725.18	72L0	2014
19	3340	10612664.54	4742310.21	5870354.33	6.076	356682.73	0.0	356682.73	55L2	2014
19	3351	2021295.20	1086712.24	934582.96	5.473	51149.73	0.0	51149.73	100R3	2014
19	3353	165466.63	94456.96	71009.67	5.460	3877.13	0.0	3877.13	100R3	2014
19	3360	997675.56	664463.87	333211.69	5.483	18270.00	0.0	18270.00	100R3	2014
19	TOTAL	94965656.83	40490939.53	53053894.67	5.768	3060040.81	0.0	3060040.81		
OTHER PRODUCTION		-SOUTHWARK G. T. (3,4,5,6)				104				
104	3401	166167.74	0.0	0.0	0.0	0.0	0.0	0.0	0	0
104	3410	106420.34	75472.99	30947.35	100.000	30947.35	0.0	30947.35	29L3	1992
104	3420	388256.08	363268.99	24987.09	100.000	24987.09	0.0	24987.09	100S1	1992
104	3440	6143618.21	5605747.35	537870.86	100.000	537870.86	0.0	537870.86	100LA	1992
104	3450	1077058.72	1000789.96	76268.76	100.000	76268.76	0.0	76268.76	91R3	1992
104	TOTAL	7881501.09	7045279.29	670074.06	100.000	670074.06	0.0	670074.06		
OTHER PRODUCTION		-EDDYSTONE G. T. (10,20,30,40)				106				
106	3401	61469.23	0.0	0.0	0.0	0.0	0.0	0.0	0	0
106	3410	185966.47	185966.47	0.0	100.000	0.0	0.0	0.0	29L3	1994
106	3420	589785.20	589785.20	0.0	100.000	0.0	0.0	0.0	100S1	1994
106	3440	6781884.03	6781884.03	0.0	100.000	0.0	0.0	0.0	100LA	1994
106	3450	697109.90	697109.90	0.0	100.000	0.0	0.0	0.0	91R3	1994
106	TOTAL	8316214.83	8254745.60	0.0	0.0	0.0	0.0	0.0		
OTHER PRODUCTION		-CROMBY DIESEL (D)				107				
107	3420	532674.51	494900.96	37773.55	100.000	37773.55	0.0	37773.55	100S1	1990
107	3440	288254.64	288254.64	0.0	100.000	0.0	0.0	0.0	100LA	1990
107	3450	18768.32	18768.32	0.0	100.000	0.0	0.0	0.0	91R3	1990
107	3460	2030.61	2030.61	0.0	100.000	0.0	0.0	0.0	75S3	1990
107	TOTAL	841728.08	803954.53	37773.55	100.000	37773.55	0.0	37773.55		
OTHER PRODUCTION		-DELAWARE DIESEL (D)				109				
109	3401	25726.23	0.0	0.0	0.0	0.0	0.0	0.0	0	0

PECO ENERGY COMPANY
PROVISION FOR DEPRECIATION
CLASS OF SERVICE: ELECTRIC
1/ 1/96 - 12/31/96

1/ 1/96 ACCRUAL RB-21
02/14/96 09:48:44

A-4f

ACCRUAL - NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
109	3420	6949.66	6949.66	0.0	100.000	0.0	0.0	0.0	100S1	1990
109	3440	260079.47	260081.65	-2.18	100.000	-2.18	0.0	-2.18	100LA	1990
109	3450	30878.81	26981.78	3897.03	100.000	3897.03	0.0	3897.03	91R3	1990
109	3460	1920.58	1920.58	0.0	100.000	0.0	0.0	0.0	75S3	1990
109	TOTAL	325554.75	295933.67	3894.85	100.000	3894.85	0.0	3894.85		
OTHER PRODUCTION			-SCHUYLKILL DIESEL (D)			113				
113	3420	5821.85	5821.85	0.0	100.000	0.0	0.0	0.0	100S1	1993
113	3440	252121.49	252121.49	0.0	100.000	0.0	0.0	0.0	100LA	1993
113	3450	31526.37	31526.37	0.0	100.000	0.0	0.0	0.0	91R3	1993
113	3460	1906.85	1906.85	0.0	100.000	0.0	0.0	0.0	75S3	1993
113	TOTAL	291376.56	291376.56	0.0	0.0	0.0	0.0	0.0		
OTHER PRODUCTION			-DELAWARE G. T. (9,10,11,12)			115				
115	3401	74933.72	0.0	0.0	0.0	0.0	0.0	0.0	0	0
115	3410	96053.43	96053.43	0.0	100.000	0.0	0.0	0.0	29L3	1994
115	3420	433232.24	433232.24	0.0	100.000	0.0	0.0	0.0	100S1	1994
115	3440	5856780.87	5856649.04	131.83	100.000	131.83	0.0	131.83	100LA	1994
115	3450	1500577.96	1500577.96	0.0	100.000	0.0	0.0	0.0	91R3	1994
115	TOTAL	7961578.22	7886512.67	131.83	100.000	131.83	0.0	131.83		
OTHER PRODUCTION			-SCHUYLKILL G. T. (10)			116				
116	3401	1048.08	0.0	0.0	0.0	0.0	0.0	0.0	0	0
116	3410	109162.36	109162.36	0.0	100.000	0.0	0.0	0.0	29L3	1994
116	3420	367307.57	367307.57	0.0	100.000	0.0	0.0	0.0	100S1	1994
116	3440	1638020.74	1638020.74	0.0	100.000	0.0	0.0	0.0	100LA	1994
116	3450	446228.62	446228.62	0.0	100.000	0.0	0.0	0.0	91R3	1994
116	TOTAL	2561767.37	2560719.29	0.0	0.0	0.0	0.0	0.0		
OTHER PRODUCTION			-CHESTER G. T. (7,8,9)			117				
117	3401	6036.22	0.0	0.0	0.0	0.0	0.0	0.0	0	0
117	3410	87338.19	87338.19	0.0	100.000	0.0	0.0	0.0	29L3	1994
117	3420	492995.77	492995.77	0.0	100.000	0.0	0.0	0.0	100S1	1994
117	3440	4402643.86	4402643.86	0.0	100.000	0.0	0.0	0.0	100LA	1994
117	3450	1121773.93	1121773.93	0.0	100.000	0.0	0.0	0.0	91R3	1994
117	TOTAL	6110787.97	6104751.75	0.0	0.0	0.0	0.0	0.0		
OTHER PRODUCTION			-KEYSTONE DIESEL (D)			118				
118	3420	8879.67	7885.62	994.05	13.471	133.91	0.0	133.91	100S1	2003
118	3440	189359.11	156811.08	32548.03	13.618	4432.39	0.0	4432.39	100LA	2003
118	3450	18873.17	16398.42	2474.75	13.406	331.76	0.0	331.76	91R3	2003
118	TOTAL	217111.95	181095.12	36016.83	13.599	4898.06	0.0	4898.06		
OTHER PRODUCTION			-FALLS G. T. (1,2,3)			119				
119	3410	137708.19	137708.19	0.0	100.000	0.0	0.0	0.0	29L3	1995
119	3420	411768.89	411768.89	0.0	100.000	0.0	0.0	0.0	100S1	1995
119	3440	4447030.06	4447030.06	0.0	100.000	0.0	0.0	0.0	100LA	1995
119	3450	887750.66	887750.66	0.0	100.000	0.0	0.0	0.0	91R3	1995
119	TOTAL	5884237.80	5884237.80	0.0	0.0	0.0	0.0	0.0		

PECO ENERGY COMPANY
PROVISION FOR DEPRECIATION
CLASS OF SERVICE: ELECTRIC
1/ 1/96 - 12/31/96

1/ 1/96 ACCRUAL RB-22
02/14/96 09:48:44

ACCRUAL - NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
OTHER PRODUCTION			-MOSER G. T. (1,2,3)			120				
120	3401	1272.20	0.0	0.0	0.0	0.0	0.0	0.0	0	0
120	3410	321514.44	321514.44	0.0	100.000	0.0	0.0	0.0	29L3	1995
120	3420	322454.72	322454.72	0.0	100.000	0.0	0.0	0.0	100S1	1995
120	3440	4372293.67	4372293.67	0.0	100.000	0.0	0.0	0.0	100LA	1995
120	3450	1056317.54	1056317.54	0.0	100.000	0.0	0.0	0.0	91R3	1995
120	TOTAL	6073852.57	6072580.37	0.0	0.0	0.0	0.0	0.0		
OTHER PRODUCTION			-CONEMAUGH DIESEL (D)			121				
121	3440	198271.38	149712.47	48558.91	9.801	4759.26	0.0	4759.26	100LA	2006
121	3450	5693.03	4101.57	1591.46	9.593	152.67	0.0	152.67	91R3	2006
121	TOTAL	203964.41	153814.04	50150.37	9.794	4911.93	0.0	4911.93		
OTHER PRODUCTION			-RICHMOND G. T. (81,91,92)			123				
123	3401	100391.29	0.0	0.0	0.0	0.0	0.0	0.0	0	0
123	3410	547052.35	112121.71	434930.64	40.008	174007.05	0.0	174007.05	29L3	1998
123	3420	907356.15	678694.27	228661.88	40.062	91606.52	0.0	91606.52	100S1	1998
123	3440	8624197.37	6363088.12	2261109.25	40.209	909169.42	0.0	909169.42	100LA	1998
123	3450	1882836.18	1521676.57	361159.61	40.051	144648.04	0.0	144648.04	91R3	1998
123	3460	1216366.62	108449.62	1107917.00	40.001	43167.88	0.0	43167.88	75S3	1998
123	TOTAL	13278199.96	8784030.29	3393778.38	40.150	1362598.91	0.0	1362598.91		
OTHER PRODUCTION			-SALEM G. T. (3)			126				
126	3420	430888.42	380953.67	49934.75	100.000	49934.75	0.0	49934.75	100S1	1996
126	3440	1575085.18	1518588.77	56496.41	100.000	56496.41	0.0	56496.41	100LA	1996
126	3450	458518.97	448610.79	9908.18	100.000	9908.18	0.0	9908.18	91R3	1996
126	3460	29580.22	29580.22	0.0	100.000	0.0	0.0	0.0	75S3	1996
126	TOTAL	2494072.79	2377733.45	116339.34	100.000	116339.34	0.0	116339.34		
OTHER PRODUCTION			-CROYDON GT(11,12,21,22,31-2,41-2			129				
129	3401	404194.53	0.0	0.0	0.0	0.0	0.0	0.0	0	0
129	3410	3528305.89	3090771.26	437534.63	31.342	137132.10	0.0	137132.10	29L3	1999
129	3420	19025733.33	15627759.71	3397973.62	28.657	973757.30	0.0	973757.30	100S1	1999
129	3440	46488230.13	34776999.12	11711231.01	28.759	3368032.93	0.0	3368032.93	100LA	1999
129	3450	3699348.26	3044084.87	655263.39	28.619	187529.83	0.0	187529.83	91R3	1999
129	3460	2191403.60	1793464.29	397939.31	28.584	113746.97	0.0	113746.97	75S3	1999
129	TOTAL	75337215.74	58333079.25	16599941.96	28.796	4780199.13	0.0	4780199.13		
OTHER PRODUCTION			-PORTABLE IN STATIONS			364				
364	3440	3045007.30	2975400.86	69606.44	100.000	69606.44	0.0	69606.44	100LA	1996
364	TOTAL	3045007.30	2975400.86	69606.44	100.000	69606.44	0.0	69606.44		
OTHER PRODUCTION			- TOTAL OF ALL STATIONS							
FUN.	3401	841219.24	0.0	0.0	0.0	0.0	0.0	0.0		
FUN.	3410	5119521.66	4216109.04	903412.62	37.866	342086.50	0.0	342086.50		
FUN.	3420	23924084.06	20183759.12	3740324.94	31.500	1178193.12	0.0	1178193.12		
FUN.	3440	94562877.51	79845326.95	14717550.56	33.637	4950497.36	0.0	4950497.36		
FUN.	3450	12933260.44	11822697.26	1110563.18	38.065	422736.27	0.0	422736.27		
FUN.	3460	2443208.48	1937352.17	505856.31	31.020	156914.85	0.0	156914.85		
FUN.	TOTAL	139824171.39	118005244.54	20977707.61	33.609	7050428.10	0.0	7050428.10		

ERGY COMPANY
SION FOR DEPRECIATION
S OF SERVICE: ELECTRIC
1/96 - 12/31/96

1/ 1/96 ACCRUAL RB-25
02/14/96 09:48:44

A-4g

ACCRUAL = NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
TRANSMISSION PLANT			-601			601				
601	3501	35244456.95	0.0	0.0	0.0	0.0	0.0	0.0	0	0
601	3502	16731622.16	0.0	0.0	0.0	0.0	0.0	0.0	0	0
601	3520	21013196.54	10731923.42	10281273.12	3.563	366521.76	0.0	366521.76	50R5	0
601	3530	318548208.37	118402507.56	200145700.81	3.499	7003098.07	0.0	7003098.07	45S2	0
601	3540	227238032.83	91571409.85	135666622.98	2.633	3572102.18	0.0	3572102.18	55L2	0
601	3550	3145700.89	235853.35	2909847.54	3.862	112378.31	0.0	112378.31	31L2	0
601	3560	115589490.72	48449004.73	67140485.99	3.457	2321046.60	0.0	2321046.60	46S2	0
601	3570	7382039.78	3223851.54	4158188.24	3.915	162793.07	0.0	162793.07	50R4	0
601	3580	55158410.37	31191502.51	23966907.86	5.526	1324611.33	0.0	1324611.33	40R4	0
601	3590	2054612.11	1629802.92	424809.19	11.351	48220.09	0.0	48220.09	30S3	0
601	TOTAL	802105770.72	305435855.88	444693835.73	3.353	14910371.41	0.0	14910371.41		
DISTRIBUTION PLANT			-601			601				
601	3601	12328300.71	0.0	0.0	0.0	0.0	0.0	0.0	0	0
601	3602	19403729.80	0.0	0.0	0.0	0.0	0.0	0.0	0	0
601	3610	47599130.59	23285286.59	24313844.00	6.910	1680086.62	0.0	1680086.62	34L5	0
601	3620	489266798.08	226941853.91	262324944.17	4.863	12756862.03	0.0	12756862.03	35R3	0
601	3640	249879400.41	67043678.89	182835721.52	2.773	5070034.56	0.0	5070034.56	46R1	0
601	3650	383963800.82	114528764.69	269435036.13	3.221	8678502.51	0.0	8678502.51	42SA	0
601	3660	198522297.25	83119746.99	115402550.26	3.585	4137181.43	0.0	4137181.43	50R4	0
601	3670	424462377.23	107980853.19	316481524.04	2.188	6924615.75	0.0	6924615.75	55RA	0
601	3680	279108487.22	79083094.12	200025393.10	3.645	7290925.58	0.0	7290925.58	36RA	0
601	3691	55110916.20	24957077.29	30153838.91	3.967	1196202.79	0.0	1196202.79	37L2	0
601	3692	173214158.27	39155773.23	134058385.04	2.522	3380952.47	0.0	3380952.47	48L1	0
601	3700	177413803.77	42513541.78	134900261.99	4.695	6333567.30	0.0	6333567.30	31RB	0
601	3702	112168.50	37863.00	74305.50	3.517	2613.32	0.0	2613.32	52S6	0
601	3710	350214.69	248943.40	101271.29	3.495	3539.43	0.0	3539.43	30O3	0
601	3730	13451942.86	2863614.94	10588327.92	7.390	782477.43	0.0	782477.43	20RB	0
601	3731	3148.98	-142515.88	145664.86	11.449	16677.17	0.0	16677.17	9O3	0
601	3732	920283.46	-6673976.25	7594259.71	3.880	294657.28	0.0	294657.28	31LB	0
601	3733	3238212.71	1902750.54	1335462.17	10.938	146072.85	0.0	146072.85	16SA	0
601	TOTAL	2528349171.35	806846350.23	1689770790.61	3.474	58694968.52	0.0	58694968.52		
GENERAL PLANT			-601			601				
601	3891	2109928.14	0.0	0.0	0.0	0.0	0.0	0.0	0	0
601	3900	35456930.95	11205919.13	24251011.82	3.113	754934.00	0.0	754934.00	44RC	0
601	3911	3643146.46	928535.61	2714610.85	5.565	151068.09	0.0	151068.09	21O2	0
601	3912	4823488.31	2019124.70	2804363.61	5.901	165485.50	0.0	165485.50	21O2	0
601	3913	7246959.23	3070758.02	4176201.21	17.865	746078.35	0.0	746078.35	8LA	0
601	3920	129812.60	5900.63	123911.97	9.523	11800.14	0.0	11800.14	11L2	0
601	3930	64243.95	-27668.33	91912.28	8.942	8218.80	0.0	8218.80	24L2	0
601	3940	8315197.49	2207766.30	6107431.19	2.668	162946.26	0.0	162946.26	45L0	0
601	3951	17482473.67	3903635.73	13578837.94	3.970	539079.87	0.0	539079.87	32LB	0
601	3952	1129576.72	403138.47	726438.25	4.117	29907.46	0.0	29907.46	35R2	0
601	3953	551830.17	256466.62	295363.55	3.298	9741.09	0.0	9741.09	49R3	0
601	3970	8679793.86	1617523.25	7062270.61	3.915	276487.89	0.0	276487.89	32R3	0
601	3980	1514120.05	553346.96	960773.09	4.810	46213.19	0.0	46213.19	27LB	0
601	3991	-564429501.16	-95889162.16	-268540339.00	0.0	0.0	0.0	0.0	0	0
601	TOTAL	-273281999.58	-69744715.09	-205647212.63	-1.411	2901960.64	0.0	2901960.64		

PECO ENERGY COMPANY
PROVISION FOR DEPRECIATION
CLASS OF SERVICE: ELECTRIC
1/ 1/96 - 12/31/96

1/ 1/96 ACCRUAL RB-24
02/14/96 09:48:44

ACCRUAL = NET PLANT, 5-YEAR NET SALVAGE — RID891364

DES	ACCT.	PLANT BALANCE 1/ 1/96	RESERVE 1/ 1/96	NET PLANT	R/L RATE	NET PLANT ACCRUAL	5-YR NET SALV. ALLOCATED	1/ 1/96 ACCRUAL	AVG. LIFE EST.	TERM YEAR
GENERAL PLANT			-601			601				
601	3992	-162990205.51	-37751260.51	-125238945.00	0.0	0.0	0.0	0.0	0	0
601	TOTAL	-162990205.51	-37751260.51	-125238945.00	0.0	0.0	0.0	0.0		
ELECTRIC		13307854903.04	4030917561.29	9116556457.25	4.458	406640121.34	0.0	406640121.34		

Adjustments to Plant Accruals that have expired Terminal Dates:

Add: Richmond	256,994.76
Less: Delaware	-1,386,031.98
Less: Cromby 2	-16,568,355.03
Less: Southwark(GT)	-331,939.06
Less: Cromby Diesel	-32,036.55
Adj. Base Depn	388,378,753.48

Attachment FG-3

	Capacity Factors for 1992 - 1996				
	1992	1993	1994	1995	1996
Limerick 1	67.2%	94.6%	85.0%	88.2%	83.9%
Limerick 2	91.6%	80.7%	92.7%	86.7%	91.9%
PB 2	61.3%	83.5%	80.8%	98.0%	79.8%
PB 3	79.0%	69.0%	97.8%	79.1%	98.2%
Conowingo 1- 11	40.1%	36.3%	43.9%	31.8%	53.4%
Cromby 1	48.1%	61.3%	47.1%	71.0%	68.3%
Cromby 2	8.5%	46.9%	48.5%	38.4%	17.0%
Delaware 7	5.8%	33.6%	28.6%	12.5%	11.1%
Delaware 8	2.7%	20.5%	18.9%	10.2%	8.5%
Eddystone 1	43.3%	35.4%	46.0%	26.2%	68.6%
Eddystone 2	32.3%	35.6%	63.3%	58.8%	71.6%
Eddystone 3	4.1%	8.4%	21.5%	23.3%	10.6%
Eddystone 4	3.1%	25.9%	20.2%	26.0%	9.3%
Muddy Run 1-8	19.8%	20.1%	20.7%	22.6%	19.7%
Schuykill 1	3.2%	23.7%	19.3%	10.4%	7.0%
CT's	0.4%	0.8%	1.5%	2.5%	2.3%
Keystone 1 & 2	79.5%	79.6%	69.8%	77.6%	84.3%
Conemaugh 1 & 2	79.6%	72.6%	73.1%	78.7%	75.9%

						PECO ENERGY				
						UNAMORTIZED ITC @ 12/31/96				
						MONTHLY AMORT BEGINNING JAN 97				
	T & D AND	STEAM &								
	OTHER ELEC	HYDRO PROD	SALEM 1	SALEM 2	EDDY SO2	CRMBY SO2	MGO	PB 2&3	CPCO sale	TOTAL
VINTAGE	255-0002	255-0002	255-0002	255-0002	255-0002	255-0002	255-0002	255-0002	255-0002	255-0002
71	203,796	142,091	0	0	0	0	0	0	70,740	416,627
72	502,193	350,123	0	0	0	0	0	0	0	852,316
73	822,873	573,734	0	0	0	0	0	0	0	1,396,607
74	1,533,181	1,068,956	0	0	0	0	0	3,796,246	0	6,398,383
75	1,354,423	620,540	0	102,151	0	0	0	197,498	0	2,274,612
76	2,746,422	1,914,844	12,286,688	505,494	0	0	0	29,043	0	17,482,491
77	904,823	630,857	801,836	779,032	0	0	0	443,040	0	3,559,588
78	1,115,502	777,759	509,329	1,580,237	0	0	0	140,133	0	4,122,960
79	1,611,752	1,123,731	838,839	1,313,107	120,273	0	0	111,804	0	5,119,506
80	1,992,154	1,388,981	959,533	612,787	1,175,544	170,449	0	338,034	0	6,637,482
81	3,114,139	278,544	287,499	1,879,813	2,690,185	877,823	0	1,384,877	0	10,512,880
82	1,371,465	2,942,657	738,392	629,446	1,786,287	1,056,052	3,610,716	947,239	0	13,082,254
83	2,131,228	898,653	695,357	865,831	0	0	655,796	289,484	0	5,536,349
84	4,122,875	1,545,085	539,088	385,797	0	0	0	482,045	0	7,074,890
85	1,627,335	2,704,172	377,669	975,270	0	0	0	3,510,979	0	9,195,425
86	1,036,319	1,003,268	276,320	190,833	0	0	0	174,635	0	2,681,375
87	1,477,714	679,207	385,829	594,991	0	0	0	471,923	0	3,609,664
88	92,192	67,345	265,524	70,064	0	0	0	223,045	0	718,170
89	49,397	76.542	0	0	0	0	0	4,965	0	130,904
90	0	86,352	0	0	0	0	0	0	0	86,352
T.B 12/31/96	27,809,783	18,873.441	18,961,903	10,484,853	5,772,289	2,104,324	4,266,512	12,544,990	70,740	100,888,835
	27,809,783	18,873.441	18,961,903	10,484,853	5,772,289	2,104,324	4,266,512	12,544,990	70,740	100,888,835
						ITC 97 YR AMORT				
97 yr. AMORT										
71	23,976	16,716	0	0	0	0	0	0	3,936	44,628
72	47,820	33,348	0	0	0	0	0	0	0	81,168
73	71,712	49,992	0	0	0	0	0	0	0	121,704
74	235,896	164,472	0	0	0	0	0	216,912	0	617,280
75	117,300	53,736	0	4,344	0	0	0	11,292	0	186,672
76	218,820	152,568	630,084	21,504	0	0	0	1,656	0	1,024,632
77	275,724	192,240	41,124	33,144	0	0	0	25,320	0	567,552
78	76,944	53,640	26,124	67,248	0	0	0	8,004	0	231,960
79	101,988	71,112	43,020	55,884	8,916	0	0	6,384	0	287,304
80	84,228	58,716	49,212	26,076	87,072	22,728	0	19,320	0	347,352
81	174,708	15,624	14,748	79,992	199,272	117,048	0	79,140	0	680,532
82	73,188	157,044	37,860	26,784	132,312	140,796	267,456	54,120	0	889,560
83	135,504	57,144	35,664	36,840	0	0	48,588	16,536	0	330,276
84	201,024	75,336	27,648	16,416	0	0	0	27,552	0	347,976
85	75,684	125,748	19,368	41,496	0	0	0	200,628	0	462,924
86	46,056	44,592	14,172	8,124	0	0	0	9,984	0	122,928
87	62,880	28,908	19,776	25,332	0	0	0	26,964	0	163,860
88	3,768	2,748	13,608	2,976	0	0	0	18,540	0	41,640
89	1,944	3,000	0	0	0	0	0	288	0	5,232
90	0	3,252	0	0	0	0	0	0	0	3,252
	2,029,164	1,359,936	972,408	446,160	427,572	280,572	316,044	722,640	3,936	6,558,432
	2,029,164	1,359,936	972,408	446,160	427,572	280,572	316,044	722,640	3,936	6,558,432

Attachment FG-4

PECO ENERGY
UNAMORTIZED ITC @ 12/31/96
MONTHLY AMORT BEGINNING JAN 97

VINTAGE	T & D AND OTHER ELEC 255-0002	STEAM & HYDRO PROD 255-0002	SALEM 1 255-0002	SALEM 2 255-0002	EDDY SO2 255-0002	CRMBY SO2 255-0002	MGO 255-0002	PB 2&3 255-0002	CPCO sale 255-0002	TOTAL 255-0002
97 MO AMORT										
71	1,998	1,393	0	0	0	0	0	0	328	3,719
72	3,985	2,779	0	0	0	0	0	0	0	6,764
73	5,976	4,166	0	0	0	0	0	0	0	10,142
74	19,658	13,706	0	0	0	0	0	18,076	0	51,440
75	9,775	4,478	0	362	0	0	0	941	0	15,556
76	18,235	12,714	52,507	1,792	0	0	0	138	0	85,386
77	22,977	16,020	3,427	2,762	0	0	0	2,110	0	47,296
78	6,412	4,470	2,177	5,604	0	0	0	667	0	19,330
79	8,499	5,926	3,585	4,657	743	0	0	532	0	23,942
80	7,019	4,893	4,101	2,173	7,256	1,894	0	1,610	0	28,946
81	14,559	1,302	1,229	6,666	16,606	9,754	0	6,595	0	56,711
82	6,099	13,087	3,155	2,232	11,026	11,733	22,288	4,510	0	74,130
83	11,292	4,762	2,972	3,070	0	0	4,049	1,378	0	27,523
84	16,752	6,278	2,304	1,368	0	0	0	2,296	0	28,998
85	6,307	10,479	1,614	3,458	0	0	0	16,719	0	38,577
86	3,838	3,716	1,181	677	0	0	0	832	0	10,244
87	5,240	2,409	1,648	2,111	0	0	0	2,247	0	13,655
88	314	229	1,134	248	0	0	0	1,545	0	3,470
89	162	250	0	0	0	0	0	24	0	436
90	0	271	0	0	0	0	0	0	0	271
	169,097	113,328	81,034	37,180	35,631	23,381	26,337	60,220	328	546,536
	169,097	113,328	81,034	37,180	35,631	23,381	26,337	60,220	328	546,536
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PECO ENERGY
UNAMORTIZED ITC @ 12/31/96
MONTHLY AMORT BEGINNING JAN 97

VINTAGE	TOTAL 255-0002	GAS 255-0003	COMMON 255-0006	Salem 2 Leas 255-0005	LIM 1 255-2001	LIM2 255-2002	LIM 1 COM 255-2003	LIM 2 COM 255-2004	GRAND TOTAL
71	416,627	106,676	3,573	0	0	0	0	0	526,876
72	852,316	517,841	69,056	0	0	0	0	0	1,439,213
73	1,396,607	274,179	60,660	0	0	0	0	0	1,731,446
74	6,398,383	150,039	47,658	0	0	0	0	0	6,596,080
75	2,274,612	357,535	8,920	0	602,152	238,786	76,625	0	3,558,630
76	17,482,491	340,418	54,948	0	2,307,104	1,192,612	315,551	0	21,693,124
77	3,559,588	368,135	9,663	0	4,104,779	2,376,140	612,178	0	11,030,483
78	4,122,960	439,131	14,557	0	4,968,372	3,881,801	875,668	0	14,302,489
79	5,119,506	941,320	26,799	0	7,536,809	3,002,999	965,343	0	17,592,776
80	6,637,482	2,074,638	21,271	0	6,982,927	1,192,880	717,284	0	17,626,482
81	10,512,880	2,392,462	227,764	6,397,717	7,454,443	1,753,203	2,033,782	0	30,772,251
82	13,082,254	1,129,549	330,366	0	8,375,137	1,817,079	1,885,129	2,807,201	29,426,715
83	5,536,349	305,537	72,511	0	13,471,680	2,719,811	3,433,809	3,475,805	29,015,502
84	7,074,890	0	0	0	13,042,699	3,854,252	633,274	4,108,370	28,713,485
85	9,195,425	1,586,155	193,674	0	11,883,122	1,832,432	2,112,309	2,232,529	29,035,646
86	2,681,375	134,010	43,131	0	1,846,666	21,594,386	182,568	178,963	26,661,099
87	3,609,664	28,535	18,560	0	322,689	19,752,269	214,893	216,499	24,163,109
88	718,170	0	0	0	0	19,561,208	650,665	642,432	21,572,475
89	130,904	0	0	0	0	19,059,185	0	45,110	19,235,199
90	86,352	138,267	0	0	0	280,494	0	0	505,113
T.B 12/31/96	100,888,835	11,284,427	1,203,111	6,397,717	82,898,579	104,109,537	14,709,078	13,706,909	335,198,193
	100,888,835	11,284,427	1,203,111	6,397,717	82,898,579	104,109,537	14,709,078	13,706,909	335,198,193
					ITC 97 YR AMORT				
97 yr. AMORT									
71	44,628	9,300	432	0	0	0	0	0	54,360
72	81,168	18,180	5,692	0	0	0	0	0	104,940
73	121,704	9,300	4,536	0	0	0	0	0	135,540
74	617,280	10,356	3,324	0	0	0	0	0	630,960
75	186,672	23,064	576	0	34,380	10,596	3,408	0	258,696
76	1,024,632	20,640	3,360	0	131,820	52,992	14,028	0	1,247,472
77	567,552	21,048	564	0	234,564	105,600	27,204	0	956,532
78	231,960	23,748	792	0	283,908	172,524	38,916	0	751,848
79	287,304	48,276	1,368	0	430,668	133,464	42,912	0	943,992
80	347,352	101,208	1,044	0	399,024	53,016	31,872	0	933,516
81	680,532	111,276	10,596	272,244	425,976	77,928	90,396	0	1,668,948
82	889,560	50,196	14,688	0	478,584	80,760	83,784	124,764	1,722,336
83	330,276	12,996	3,084	0	769,824	120,888	152,604	154,476	1,544,148
84	347,976	0	0	0	745,296	171,300	28,140	182,592	1,475,304
85	462,924	62,196	7,596	0	679,044	81,456	93,888	99,228	1,486,332
86	122,928	5,052	1,632	0	105,528	959,748	8,124	7,944	1,210,956
87	163,860	1,032	672	0	18,444	877,884	9,552	9,624	1,081,068
88	41,640	0	0	0	0	869,388	28,920	28,560	968,508
89	5,232	0	0	0	0	847,080	0	2,004	854,316
90	3,252	4,536	0	0	0	12,456	0	0	20,244
	6,558,432	532,404	59,856	272,244	4,737,060	4,627,080	653,748	609,192	18,050,016
	6,558,432	532,404	59,856	272,244	4,737,060	4,627,080	653,748	609,192	18,050,016

PAGE 3

PECO ENERGY
UNAMORTIZED ITC @ 12/31/96
MONTHLY AMORT BEGINNING JAN 97

VINTAGE	TOTAL 255-0002	GAS 255-0003	COMMON 255-0006	Salem 2 Leas 255-0005	LIM 1 255-2001	LIM2 255-2002	LIM 1 COM 255-2003	LIM 2 COM 255-2004	GRAND TOTAL
97 MO AMORT									
71	3,719	775	36	0	0	0	0	0	4,530
72	6,764	1,515	466	0	0	0	0	0	8,745
73	10,142	775	378	0	0	0	0	0	11,295
74	51,440	863	277	0	0	0	0	0	52,580
75	15,556	1,922	48	0	2,865	883	284	0	21,558
76	85,386	1,720	280	0	10,985	4,416	1,169	0	103,956
77	47,296	1,754	47	0	19,547	8,800	2,267	0	79,711
78	19,330	1,979	66	0	23,659	14,377	3,243	0	62,654
79	23,942	4,023	114	0	35,889	11,122	3,576	0	78,666
80	28,946	8,434	87	0	33,252	4,418	2,656	0	77,793
81	56,711	9,273	883	22,687	35,498	6,494	7,533	0	139,079
82	74,130	4,183	1,224	0	39,882	6,730	6,982	10,397	143,528
83	27,523	1,083	257	0	64,152	10,074	12,717	12,873	128,679
84	28,998	0	0	0	62,108	14,275	2,345	15,216	122,942
85	38,577	5,183	633	0	56,587	6,788	7,824	8,269	123,861
86	10,244	421	136	0	8,794	79,979	677	662	100,913
87	13,655	86	56	0	1,537	73,157	796	802	90,089
88	3,470	0	0	0	0	72,449	2,410	2,380	80,709
89	436	0	0	0	0	70,590	0	167	71,193
90	271	378	0	0	0	1,038	0	0	1,687
	546,536	44,367	4,988	22,687	394,755	385,590	54,479	50,766	1,504,168
	546,536	44,367	4,988	22,687	394,755	385,590	54,479	50,766	1,504,168

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1								Federal		Federal		State		State	
2						Federal		Deferred	1996	Deferred	1996	Deferred	1996	Deferred	1996
3					Allowable	Deferred Tax		Taxes	Deferred	Tax	Deferred	Taxes	Deferred	Taxes	Deferre
4	VINTAGE	Tax Bases	Tax Reserve	Net	Tax	Assoc.	1996 Deferrec	Assoc W	Taxes	Assoc	Taxes	Assoc	Taxes	Assoc W	Taxes
5					Depn 1996	w Depn	Taxes	AFUDC	AFUDC	w Avoided	Avoided	w AFUDC	AFUDC	Avoided	Avoided
6								Debt	Debt	AFUDC	AFUDC	Debt	Debt	AFUDC	AFUDC
7	Summary														
8															
9	Limerick	3,874,568,747	3,386,526,958	488,041,789	172,312,595	899,564,072	20,263,968	5,801,805	-167,653	-3,596,425	425,525	1,289,050	-41,406	-821,326	96,971
10	Steam Pro	1,422,239,911	1,085,177,592	337,062,319	43,435,557	19,060,454	-10,875,887	2,994,926	-423,168	-4,822,937	396,194	670,118	-105,610	-1,124,092	92,280
11	Peach Bot	717,813,081	517,121,771	200,691,310	20,834,394	33,833,611	612,557	2,094,988	-92,978	-2,514,465	336,728	462,972	-22,939	-563,846	75,326
12	Hydraulic	86,928,865	55,925,083	31,003,781	1,869,089	1,451,513	68,124	126,226	-6,380	-160,739	13,075	28,636	-1,602	-37,543	3,053
13	Salem	796,832,877	599,944,318	196,888,559	25,623,587	55,654,908	-2,350,532	5,831,117	-236,983	-6,908,215	870,206	1,327,874	-59,896	-1,598,583	202,496
14															
15	Prod Plant	6,898,383,481	5,644,695,722	1,253,687,758	264,075,222	1,009,564,558	7,718,230	16,849,062	-927,162	-18,002,781	2,041,728	3,778,650	-231,453	-4,145,390	470,126
16	Prod % of	69%	70%	67%	71%	83%	51%	61%	77%	56%	64%	61%	78%	56%	65%
17	Total														
18	Elec Gen	1,229,064	704,224	524,840	226,879	165,556	54,893	9,970	-538	-9,424	4,076	2,472	-142	-2,459	1,064
19	Buildings	98,763,852	43,399,516	55,364,336	3,016,400	655,381	-98,340	435,205	-19,967	-665,596	24,910	96,799	-4,929	-150,296	5,591
20															
21															
22	T & D	2,964,947,433	2,060,508,657	904,438,776	103,526,342	211,482,571	7,319,764	10,202,473	-251,116	-13,480,028	1,116,898	2,276,309	-62,024	-3,041,084	251,863
23															
24	Non Depr														
25	Intangible	74,764,297	0	74,764,297	0	0	0	0	0	0	0	0	0	0	0
26	Disallowan	-183,956,871	343,462,835	-527,419,706	0	0	0	0	0	0	0	0	0	0	0
27	Steam	9,153,458	0	9,153,458	0	0	0	0	0	0	0	0	0	0	0
28	Salem	75,626	0	75,626	0	0	0	0	0	0	0	0	0	0	0
29	Limerick	7,903,504	0	7,903,504	0	0	0	0	0	0	0	0	0	0	0
30	PeachBot	3,427,032	0	3,427,032	0	0	0	0	0	0	0	0	0	0	0
31	Hydraulic	1,420,823	0	1,420,823	0	0	0	0	0	0	0	0	0	0	0
32	T & D	88,415,610	0	88,415,610	0	0	0	0	0	0	0	0	0	0	0
33	General	2,109,928	0	2,109,928	0	0	0	0	0	0	0	0	0	0	0
34															
35	Tot Non De	3,313,407	343,462,835	-340,149,428	0	0	0	0	0	0	0	0	0	0	0
36															
37	Total Elec	9,966,637,237	8,092,770,954	1,873,866,282	370,844,843	1,221,868,066	14,994,547	27,496,710	-1,198,783	-32,157,829	3,187,612	6,154,230	-298,548	-7,339,229	728,644
38															
39															
40															
41															
42															
43															
44															
45															
46															
47															

Attachment FG-5

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1–48	VINTAGE	Tax Bases	Tax Reserve	Net	Allowable Tax Depn 1996	Federal Deferred Tax Assoc. w Depn	1996 Deferred Taxes	Federal Deferred Taxes Assoc W AFUDC Debt	1996 Deferred Taxes AFUDC Debt	Federal Deferred Tax Assoc w Avoided AFUDC	1996 Deferred Taxes Avoided AFUDC	State Deferred Taxes Assoc w AFUDC Debt	1996 Deferred Taxes AFUDC Debt	State Deferred Taxes Assoc W Avoided AFUDC	1996 Deferre Taxes Avoided AFUDC
49	**Electric General Plant**														
50								Debt Fed	Fed	AFUDC Fed	AFUDC Fe	Debt State	State	AFUDC Sta	AFUDC St
51	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
52	V1982	24,042	24,042	0	0	-142	0	0	0	0	0	0	0	0	0
53	V1986	500	500	0	0	0	-10	0	0	0	0	0	0	0	0
54	V1987	19,305	19,305	0	0	343	-643	41	-5	0	0	9	-1	0	0
55	V1989	80,157	80,157	0	0	16,689	-1,187	526	-25	0	0	115	-6	0	0
56	V1992	342,189	268,356	73,833	30,934	64,957	4,852	4,654	-219	-3,155	1,352	1,018	-54	-697	299
57	V1995	762,871	311,864	451,007	195,944	83,709	51,881	4,749	-291	-6,270	2,724	1,330	-81	-1,762	765
58															
59		-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
60		1,229,064	704,224	524,840	226,879	165,556	54,893	9,970	-538	-9,424	4,076	2,472	-142	-2,459	1,064
61		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
62															
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1								Federal		Federal		State		State	
2						Federal		Deferred	1996	Deferred	1996	Deferred	1996	Deferred	1996
3					Allowable	Deferred Tax		Taxes	Deferred	Tax	Deferred	Taxes	Deferred	Taxes	Deferre
4	VINTAGE	Tax Bases	Tax Reserve	Net	Tax	Assoc.	1996 Deferred	Assoc W	Taxes	Assoc	Taxes	Assoc	Taxes	Assoc W	Taxes
5					Depn 1996	w Depn	Taxes	AFUDC	AFUDC	w Avoided	Avoided	w AFUDC	AFUDC	Avoided	Avoided
6								Debt	Debt	AFUDC	AFUDC	Debt	Debt	AFUDC	AFUDC
89	**Limerick Plant**														
90	-------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------
91	V1980	6,300	6,300	0	23	490	-130	0	0	0	0	0	0	0	0
92	V1981	78	78	0	0	16	-1	0	0	0	0	0	0	0	0
93	V1983	40,884	40,884	0	0	9,019	-492	0	0	0	0	0	0	0	0
94	V1985	1,883,822,613	1,873,179,411	10,643,202	3,084,465	519,708,462	-18,479,256	0	0	0	0	0	0	0	0
95	V1986	35,334,492	35,334,492	0	4	8,934,197	-445,593	0	0	0	0	0	0	0	0
96	V1987A	12,131,776	12,131,776	0	1,091,858	3,062,027	258,538	14,455	-402	0	4,160	3,177	-99	0	920
97	V1987	44,373,862	29,961,700	14,412,162	2,620,393	6,133,548	457,655	74,083	-2,083	-43,933	7,988	16,280	-511	-9,712	1,766
98	V1988A	22,025,938	19,752,797	2,273,141	1,948,538	4,938,875	456,589	10,595	-289	-23,684	21,901	2,328	-71	-5,236	4,841
99	V1988	2,355,101	1,021,410	1,333,691	105,945	152,403	11,834	29,362	-848	-37,975	3,056	6,451	-208	-8,395	676
100	V1989A	1,640,393,603	1,344,788,251	295,605,351	147,635,424	341,728,689	35,066,418	792,899	-21,799	-2,231	795	174,251	-5,342	-493	176
101	V1989	26,866,146	14,185,848	12,680,298	1,521,342	2,811,457	245,595	103,003	-2,980	-170,660	22,734	22,632	-730	-37,726	5,025
102	V1990	27,251,876	13,176,514	14,075,362	1,573,784	2,680,686	248,004	2,396,686	-66,301	-611,200	71,729	526,697	-16,249	-135,110	15,856
103	V1991	4,331,834	1,516,031	2,815,803	226,508	530,760	34,680	87,940	-2,509	-131,766	8,061	19,324	-615	-29,128	1,782
104	V1992	59,314,628	22,337,250	36,977,378	4,106,764	4,849,138	748,562	827,216	-26,003	-861,720	95,688	181,663	-6,373	-190,489	21,152
105	V1993	30,301,128	8,619,470	21,681,658	2,176,532	1,829,274	395,507	783,267	-22,194	-797,490	87,953	172,120	-5,439	-176,291	19,443
106	V1994	21,899,127	4,320,200	17,578,927	1,622,970	891,481	298,311	446,710	-13,146	-476,939	52,993	98,145	-3,222	-105,431	11,715
107	V1995	31,319,361	4,514,544	26,804,817	2,958,045	946,392	610,587	235,587	-9,098	-438,827	48,466	65,983	-2,548	-123,317	13,620
108	V1996	32,800,000	1,640,000	31,160,000	1,640,000	357,160	357,160	0	0	0	0	0	0	0	0
109															
110		-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------
111		3,874,568,747	3,386,526,958	488,041,789	172,312,595	899,564,072	20,263,968	5,801,805	-167,653	-3,596,425	425,525	1,289,050	-41,406	-821,326	96,971
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1–6	VINTAGE	Tax Bases	Tax Reserve	Net	Allowable Tax Depn 1996	Federal Deferred Tax Assoc. w Depn	1996 Deferrec Taxes	Federal Deferred Taxes Assoc W AFUDC Debt	1996 Deferred Taxes AFUDC Debt	Federal Deferred Tax Assoc w Avoided AFUDC	1996 Deferred Taxes Avoided AFUDC	State Deferred Taxes Assoc w AFUDC Debt	1996 Deferred Taxes AFUDC Debt	State Deferred Taxes Assoc W Avoided AFUDC	1996 Deferre Taxes Avoided AFUDC
130	**Steam Production Plant**														
131	--------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
132	V1953	49,710,076	49,710,076	0	0	0	0	0	0	0	0	0	0	0	0
133	V1969	221,341,878	221,341,878	0	0	0	0	0	0	0	0	0	0	0	0
134	V1970	36,801,558	36,801,558	0	104,125	43,057	35,005	0	0	0	0	0	0	0	0
135	V1971	40,934,604	40,934,604	0	0	1,716,279	-670,425	0	0	0	0	0	0	0	0
136	V1972	5,081,191	5,074,779	6,412	-1,548	0	-40,154	0	0	0	0	0	0	0	0
137	V1973	26,615,511	26,615,511	0	9,887	1,904,105	-363,015	0	0	0	0	0	0	0	0
138	V1974	191,871,754	191,871,754	0	68,997	10,778,093	-3,172,963	0	0	0	0	0	0	0	0
139	V1975	28,649,128	27,942,047	707,081	564,537	1,517,881	-185,855	0	0	0	0	0	0	0	0
140	V1976	83,456,609	82,632,790	823,819	943,927	3,533,201	-931,026	0	0	0	0	0	0	0	0
141	V1977	6,220,547	5,922,493	298,054	102,972	646,477	-48,926	0	0	0	0	0	0	0	0
142	V1978	3,789,557	3,355,257	434,300	108,575	0	0	0	0	0	0	0	0	0	0
143	V1979	12,815,034	11,692,052	1,122,982	325,130	1,149,493	-46,953	0	0	0	0	0	0	0	0
144	V1980	2,982,409	2,430,572	551,837	91,973	0	0	0	0	0	0	0	0	0	0
145	V1981	6,763,331	6,763,331	0	0	-33,035	0	0	0	0	0	0	0	0	0
146	V1982	193,255,298	193,255,298	0	11,445,309	16,549,943	1,461,300	0	0	0	0	0	0	0	0
147	V1983	16,938,283	15,921,917	1,016,366	1,016,297	1,559,867	123,218	0	0	0	0	0	0	0	0
148	V1984	22,858,373	20,115,369	2,743,005	1,371,502	2,338,272	126,024	0	0	0	0	0	0	0	0
149	V1985	20,101,801	16,483,477	3,618,324	1,206,108	1,275,164	33,429	0	0	0	0	0	0	0	0
150	V1986	24,225,806	18,411,611	5,814,195	1,453,548	929,026	-21,732	0	0	0	0	0	0	0	0
151	V1987A	5,599,899	3,919,930	1,679,969	335,994	233,360	-1,105	12,679	-778	-18,318	3,664	2,765	-191	-4,049	810
152	V1987	19,634,586	10,436,470	9,198,116	876,011	-287,400	-108,410	45,671	-2,803	-77,596	7,390	9,961	-687	-17,153	1,634
153	V1988A	1,087,977	696,306	391,671	65,279	23,642	-2,898	6,991	-493	-6,760	1,126	1,522	-121	-1,494	249
154	V1988	15,253,696	7,427,304	7,826,392	680,556	-440,013	-124,229	105,527	-7,439	-115,772	10,066	22,970	-1,823	-25,592	2,225
155	V1989A	1,132,769	657,006	475,763	67,966	-105,466	-23,865	5,811	-822	-9,953	1,422	1,245	-201	-2,200	314
156	V1989	6,031,048	2,667,564	3,363,484	272,715	-826,932	-156,779	33,741	-4,771	-63,573	5,154	7,230	-1,169	-14,053	1,139
157	V1990A	1,383,480	719,409	664,071	83,009	-58,448	-18,889	8,361	-909	0	0	1,805	-223	0	0
158	V1990	56,375,111	22,386,060	33,989,051	2,755,869	-4,535,549	-942,045	339,378	-36,900	-802,168	65,041	73,249	-9,043	-177,325	14,378
159	V1991	19,562,285	6,811,769	12,750,517	1,033,826	-946,212	-242,131	172,777	-16,634	-205,916	16,693	37,395	-4,077	-45,519	3,690
160	V1992	60,798,900	17,957,526	42,841,374	3,473,625	-6,953,410	-1,077,386	724,124	-90,245	-966,101	78,333	155,738	-22,117	-213,564	17,316
161	V1993	52,366,118	12,474,990	39,891,128	3,234,416	-5,164,940	-1,571,299	447,438	-83,987	-666,111	54,009	94,875	-20,583	-147,249	11,939
162	V1994	63,437,352	11,194,215	52,243,137	4,235,930	-4,303,584	-1,785,449	655,561	-123,053	-924,196	74,935	139,006	-30,157	-204,300	16,565
163	V1995	81,163,940	8,902,670	72,261,270	5,859,022	-1,112,048	-748,960	436,866	-54,335	-966,473	78,363	122,357	-15,218	-271,593	22,021
164	V1996	44,000,000	1,650,000	42,350,000	1,650,000	-370,370	-370,370	0	0	0	0	0	0	0	0
165															
166		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
167		1,422,239,911	1,085,177,592	337,062,319	43,435,557	19,060,454	-10,875,887	2,994,926	-423,168	-4,822,937	396,194	670,118	-105,610	-1,124,092	92,280
168		===========	===========	===========	===========	===========	===========	===========	===========	===========	===========	===========	===========	===========	===========
169															
170															

Plant est. at 12/31/96

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1								Federal		Federal		State		State	
2						Federal		Deferred	1996	Deferred	1996	Deferred	1996	Deferred	1996
3					Allowable	Deferred Tax		Taxes	Deferred	Tax	Deferred	Taxes	Deferred	Taxes	Deferre
4	VINTAGE	Tax Bases	Tax Reserve	Net	Tax	Assoc.	1996 Deferred	Assoc W	Taxes	Assoc	Taxes	Assoc	Taxes	Assoc W	Taxes
5					Depn 1996	w Depn	Taxes	AFUDC	AFUDC	w Avoided	Avoided	w AFUDC	AFUDC	Avoided	Avoided
6								Debt	Debt	AFUDC	AFUDC	Debt	Debt	AFUDC	AFUDC
171															
172	**Peach Bottom**														
173	-------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
174	V1953	224	224	0	0	0	0	0	0	0	0	0	0	0	0
175	V1969	141,482	141,482	0	0	0	0	0	0	0	0	0	0	0	0
176	V1970	359	359	0	0	0	0	0	0	0	0	0	0	0	0
177	V1971	173,118	173,118	0	0	0	0	0	0	0	0	0	0	0	0
178	V1972	49,241	49,241	0	0	0	0	0	0	0	0	0	0	0	0
179	V1973	565,237	565,237	0	0	0	0	0	0	0	0	0	0	0	0
180	V1974	269,766,586	269,766,586	0	0	-176,414	0	0	0	0	0	0	0	0	0
181	V1975	5,460,143	5,460,143	0	0	0	0	0	0	0	0	0	0	0	0
182	V1976	3,636,506	3,636,506	0	0	132,894	-101,163	0	0	0	0	0	0	0	0
183	V1977	3,761,952	3,761,952	0	0	33,822	-60,988	0	0	0	0	0	0	0	0
184	V1978	3,269,562	3,269,562	0	0	193,983	-80,504	0	0	0	0	0	0	0	0
185	V1979	2,363,001	2,363,001	0	10,664	143,249	-50,081	0	0	0	0	0	0	0	0
186	V1980	7,015,329	7,015,329	0	726	660,298	-155,060	0	0	0	0	0	0	0	0
187	V1981	26,467,436	26,467,436	0	0	4,689,540	-393,254	0	0	0	0	0	0	0	0
188	V1982	15,188,781	15,188,781	0	0	2,861,175	-224,885	0	0	0	0	0	0	0	0
189	V1983	3,634,804	3,634,804	0	0	731,980	-55,584	0	0	0	0	0	0	0	0
190	V1984	9,553,604	9,553,604	0	0	1,798,544	-141,818	0	0	0	0	0	0	0	0
191	V1985	37,171,394	37,171,394	0	0	3,601,623	-572,198	0	0	0	0	0	0	0	0
192	V1986	4,386,834	4,386,834	0	0	661,655	-59,920	0	0	0	0	0	0	0	0
193	V1987A	8,145,708	8,145,708	0	733,114	1,566,247	123,569	18,950	-859	70	18,652	4,148	-211	15	4,123
194	V1987	13,211,070	8,920,237	4,290,834	780,152	1,101,571	59,165	31,575	-1,431	-45,473	8,287	6,911	-351	-10,052	1,832
195	V1988A	6,740,412	6,133,775	606,637	606,637	1,110,947	96,562	45,128	-2,143	-18,610	18,610	9,873	-525	-4,114	4,114
196	V1988	39,330,348	24,229,599	15,100,750	2,323,192	2,671,521	147,454	283,489	-13,461	-268,198	41,261	62,021	-3,299	-59,287	9,121
197	V1989A	84,131	68,987	15,144	7,572	14,552	1,447	514	-20	-475	238	113	-5	-105	53
198	V1989	16,522,543	9,205,773	7,316,770	975,569	1,420,995	110,633	110,177	-4,194	-160,681	21,424	24,154	-1,028	-35,520	4,736
199	V1990A	4,565,066	3,332,498	1,232,568	410,856	705,816	78,584	28,764	-1,143	0	0	6,304	-280	0	0
200	V1990	42,154,758	20,996,590	21,158,168	2,489,196	3,220,650	256,226	264,479	-10,511	-564,520	66,414	57,960	-2,576	-124,791	14,681
201	V1991	42,311,434	18,576,179	23,735,255	2,637,251	2,806,335	269,357	410,630	-17,474	-421,546	46,838	89,933	-4,283	-93,186	10,354
202	V1992	27,735,464	10,448,088	17,287,376	1,920,820	1,604,524	216,874	378,677	-16,997	-417,219	46,358	82,893	-4,165	-92,229	10,248
203	V1993	8,342,768	2,564,984	5,777,784	641,976	412,520	85,975	89,874	-4,086	-100,463	11,163	19,671	-1,001	-22,208	2,468
204	V1994	27,830,566	6,414,945	21,415,620	2,379,513	1,091,021	369,171	362,985	-16,292	-383,833	42,648	79,458	-3,993	-84,849	9,428
205	V1995	11,233,219	1,628,817	9,604,402	1,067,156	230,173	148,605	69,744	-4,366	-133,516	14,835	19,534	-1,223	-37,520	4,169
206	V1996	77,000,000	3,850,000	73,150,000	3,850,000	544,390	544,390	0	0	0	0	0	0	0	0
207															
208		------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
209		717,813,081	517,121,771	200,691,310	20,834,394	33,833,611	612,557	2,094,988	-92,978	-2,514,465	336,728	462,972	-22,939	-563,846	75,326
210		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
211															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1–6	VINTAGE	Tax Bases	Tax Reserve	Net	Allowable Tax *Depn 1996*	Federal Deferred Tax Assoc. *w Depn*	1996 Deferrec *Taxes*	*Federal* Deferred Taxes Assoc W *AFUDC* Debt	1996 Deferred Taxes AFUDC Debt	*Federal* Deferred Tax Assoc *w Avoided* AFUDC	1996 Deferred Taxes *Avoided* AFUDC	*State* Deferred Taxes Assoc w AFUDC Debt	1996 Deferred Taxes AFUDC Debt	*State* Deferred Taxes Assoc W *Avoided* AFUDC	1996 Deferre Taxes *Avoided* AFUDC
212															
213	Hydraulic Production														
214	--------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
215	V1953	96	96	0	0	0	0	0	0	0	0	0	0	0	0
216	V1969	65,603,858	45,286,577	20,317,282	902,990	0	0	0	0	0	0	0	0	0	0
217	V1970	1,563,309	1,193,727	369,582	30,925	139,509	-132	0	0	0	0	0	0	0	0
218	V1971	361,227	308,044	53,183	6,826	48,012	-142	0	0	0	0	0	0	0	0
219	V1972	224,381	188,863	35,518	4,532	32,469	17	0	0	0	0	0	0	0	0
220	V1973	1,140,171	909,496	230,675	23,533	130,284	427	0	0	0	0	0	0	0	0
221	V1974	1,544,703	1,154,474	390,229	31,440	116,559	724	0	0	0	0	0	0	0	0
222	V1975	2,705,546	1,955,670	749,876	58,714	229,046	2,196	0	0	0	0	0	0	0	0
223	V1976	1,984	1,501	483	50	276	3	0	0	0	0	0	0	0	0
224	V1977	461,171	334,248	126,923	11,865	55,323	932	0	0	0	0	0	0	0	0
225	V1978	65,234	46,006	19,228	1,788	8,669	169	0	0	0	0	0	0	0	0
226	V1979	446,547	291,742	154,805	11,864	40,816	961	0	0	0	0	0	0	0	0
227	V1980	1,342	871	471	40	165	5	0	0	0	0	0	0	0	0
228	V1981	93,085	93,085	0	1	26,797	-512	0	0	0	0	0	0	0	0
229	V1982	1,358,251	1,358,248	3	81,495	338,567	18,300	0	0	0	0	0	0	0	0
230	V1983	79,757	74,971	4,786	4,785	14,961	760	0	0	0	0	0	0	0	0
231	V1984	27,684	24,359	3,325	1,661	6,896	429	0	0	0	0	0	0	0	0
232	V1986	2,863	2,175	688	172	612	47	0	0	0	0	0	0	0	0
233	V1987A	58,373	40,861	17,512	3,502	7,358	832	143	-3	-191	38	32	-1	-42	8
234	V1987	5,773	3,069	2,704	258	380	52	15	0	-23	2	3	0	-5	0
235	V1988	434,416	211,526	222,891	19,382	55,482	4,927	3,358	-35	-3,297	287	741	-9	-729	63
236	V1989	39,863	17,632	22,231	1,802	1,931	81	266	-10	-420	34	58	-2	-93	8
237	V1990	53,756	21,346	32,410	2,628	2,324	145	374	-15	-765	62	82	-4	-169	14
238	V1991	54,138	18,851	35,287	2,861	1,523	91	521	-25	-570	46	114	-6	-126	10
239	V1992	5,706,568	1,685,488	4,021,080	326,033	134,169	13,491	77,248	-3,829	-90,678	7,352	16,892	-938	-20,045	1,625
240	V1993	312,336	74,407	237,930	19,292	6,925	1,294	3,343	-164	-3,973	322	731	-40	-878	71
241	V1994	1,873,727	330,640	1,543,088	125,115	33,451	10,839	24,259	-1,187	-27,298	2,213	5,306	-291	-6,034	489
242	V1995	2,708,706	297,111	2,411,594	195,535	19,009	12,188	16,698	-1,113	-33,525	2,718	4,677	-312	-9,421	764
243															
244		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
245		86,928,865	55,925,083	31,003,781	1,869,089	1,451,513	68,124	126,226	-6,380	-160,739	13,075	28,636	-1,602	-37,543	3,053
246		===========	===========	===========	===========	===========	===========	===========	===========	===========	===========	===========	===========	===========	===========
247															
248															
249															
250															
251															
252															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1								Federal		Federal		State		State	
2						Federal		Deferred	1996	Deferred	1996	Deferred	1996	Deferred	1996
3					Allowable	Deferred Tax		Taxes	Deferred	Tax	Deferred	Taxes	Deferred	Taxes	Deferre
4	VINTAGE	Tax Bases	Tax Reserve	Net	Tax	Assoc.	1996 Deferred	Assoc W	Taxes	Assoc	Taxes	Assoc	Taxes	Assoc W	Taxes
5					Depn 1996	w Depn	Taxes	AFUDC	AFUDC	w Avoided	Avoided	w AFUDC	AFUDC	Avoided	Avoided
6								Debt	Debt	AFUDC	AFUDC	Debt	Debt	AFUDC	AFUDC
253	**Transmission and Distribution Plant**														
254	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
255	V1953	144,385,535	144,385,535	0	0	0	0	0	0	0	0	0	0	0	0
256	V1969	498,894,799	488,925,004	9,969,795	12,933,479	0	0	0	0	0	0	0	0	0	0
257	V1970	79,363,552	77,495,576	1,867,976	994,316	4,499,350	-737,159	0	0	0	0	0	0	0	0
258	V1971	121,126,237	121,126,237	0	0	6,533,207	-1,785,742	0	0	0	0	0	0	0	0
259	V1972	77,686,600	77,686,600	0	0	4,666,695	-1,042,513	0	0	0	0	0	0	0	0
260	V1973	85,706,668	85,678,734	27,934	352,336	6,211,744	-1,119,541	0	0	0	0	0	0	0	0
261	V1974	84,138,175	83,817,705	320,470	258,382	7,720,635	-1,121,766	0	0	0	0	0	0	0	0
262	V1975	54,908,662	54,479,176	429,486	171,794	5,175,818	-706,738	0	0	0	0	0	0	0	0
263	V1976	40,661,807	40,133,749	528,058	658,129	4,643,275	-291,675	0	0	0	0	0	0	0	0
264	V1977	42,961,249	41,678,260	1,282,989	843,154	4,442,053	-217,351	0	0	0	0	0	0	0	0
265	V1978	45,199,104	43,020,372	2,178,731	994,343	5,676,754	-206,778	0	0	0	0	0	0	0	0
266	V1979	38,237,398	35,346,852	2,890,546	964,811	4,420,993	-112,457	0	0	0	0	0	0	0	0
267	V1980	33,928,090	31,606,683	2,321,407	948,067	4,266,736	-68,668	0	0	0	0	0	0	0	0
268	V1981	45,362,548	45,362,548	0	270	10,245,969	-476,018	0	0	0	0	0	0	0	0
269	V1982	26,478,895	26,478,895	0	1,588,733	6,074,602	307,595	0	0	0	0	0	0	0	0
270	V1983	83,695,208	78,673,495	5,021,713	5,021,712	18,437,728	978,523	0	0	0	0	0	0	0	0
271	V1984	72,252,557	63,582,252	8,670,306	4,335,153	14,313,547	801,868	0	0	0	0	0	0	0	0
272	V1985	65,690,249	53,866,005	11,824,244	3,941,415	12,373,949	781,345	0	0	0	0	0	0	0	0
273	V1986	60,842,520	46,240,315	14,602,206	3,650,551	10,661,098	737,048	0	0	0	0	0	0	0	0
274	V1987A	31,374,572	21,962,201	9,412,371	1,882,474	4,679,632	346,151	76,086	-2,028	-103,324	20,526	16,722	-497	-22,841	4,537
275	V1987	106,728,604	56,729,992	49,998,612	4,761,773	9,926,081	607,752	265,887	-7,092	-424,113	40,171	58,435	-1,738	-93,753	8,880
276	V1988A	1,846,277	1,181,618	664,659	110,777	248,109	20,359	12,876	-339	-11,491	1,912	2,830	-83	-2,540	423
277	V1988	119,441,426	58,158,222	61,283,204	5,328,974	10,495,877	737,947	899,244	-22,547	-908,196	78,817	197,701	-5,526	-200,763	17,423
278	V1989A	821,536	476,490	345,046	49,292	109,727	10,070	5,180	-116	-7,229	1,031	1,140	-28	-1,598	228
279	V1989	157,118,956	69,494,553	87,624,403	7,104,681	12,823,658	1,005,435	1,075,838	-26,515	-1,658,303	134,271	236,548	-6,498	-366,580	29,682
280	V1990	201,841,450	80,149,463	121,691,987	9,866,918	14,829,760	1,502,098	1,443,989	-36,340	-2,874,125	232,867	317,459	-8,906	-635,346	51,477
281	V1991	88,422,099	30,789,394	57,632,705	4,672,922	6,496,839	842,248	891,243	-20,383	-931,509	75,451	196,037	-4,995	-205,917	16,679
282	V1992	144,018,728	42,574,986	101,443,743	8,225,168	9,096,682	1,545,468	2,049,876	-47,562	-2,291,085	185,552	450,855	-11,656	-506,461	41,018
283	V1993	124,970,079	29,771,168	95,198,911	7,718,831	5,895,692	1,494,905	1,479,289	-40,639	-1,689,768	137,061	325,040	-9,960	-373,535	30,298
284	V1994	98,158,197	17,321,088	80,837,110	6,554,360	3,791,132	1,369,534	1,454,106	-33,775	-1,559,704	126,441	319,818	-8,277	-344,784	27,951
285	V1995	72,585,655	7,961,739	64,623,916	5,239,777	1,764,211	1,156,808	548,859	-13,779	-1,021,182	82,799	153,724	-3,859	-286,967	23,268
286	V1996	116,100,000	4,353,750	111,746,250	4,353,750	961,018	961,018	0	0	0	0	0	0	0	0
287															
288		--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
289		2,964,947,433	2,060,508,657	904,438,776	103,526,342	211,482,571	7,319,764	10,202,473	-251,116	-13,480,028	1,116,898	2,276,309	-62,024	-3,041,084	251,863
290		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
291															
292															
293															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1								Federal		Federal		State		State	
2						Federal		Deferred	1996	Deferred	1996	Deferred	1996	Deferred	1996
3					Allowable	Deferred Tax		. Taxes	Deferred	Tax	Deferred	Taxes	Deferred	Taxes	Deferre
4	VINTAGE	Tax Bases	Tax Reserve	Net	Tax	Assoc.	1996 Deferred	Assoc W	Taxes	Assoc	Taxes	Assoc	Taxes	Assoc W	Taxes
5					Depn 1996	w Depn	Taxes	AFUDC	AFUDC	w Avoided	Avoided	w AFUDC	AFUDC	Avoided	Avoided
6								Debt	Debt	AFUDC	AFUDC	Debt	Debt	AFUDC	AFUDC
294	**Electric Buildings**														
295	--------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
296	V1969	14,460,582	10,862,989	3,597,592	272,867	0	0	0	0	0	0	0	0	0	0
297	V1970	1,222,351	836,388	385,963	27,242	108,042	16	0	0	0	0	0	0	0	0
298	V1971	1,496,702	937,129	559,573	24,392	-44,041	-3,389	0	0	0	0	0	0	0	0
299	V1972	745,272	467,244	278,028	10,862	64,690	-2,226	0	0	0	0	0	0	0	0
300	V1973	538,213	309,845	228,367	9,514	13,889	-1,089	0	0	0	0	0	0	0	0
301	V1974	4,147,198	2,408,917	1,738,281	68,414	137,465	-10,736	0	0	0	0	0	0	0	0
302	V1975	953,880	502,994	450,886	19,187	21,287	-805	0	0	0	0	0	0	0	0
303	V1976	13,495	5,242	8,253	337	456	13	0	0	0	0	0	0	0	0
304	V1977	528,227	232,434	295,793	10,379	12,414	-538	0	0	0	0	0	0	0	0
305	V1978	659,204	300,413	358,791	13,539	18,020	-465	0	0	0	0	0	0	0	0
306	V1979	857,092	375,322	481,770	17,519	22,461	-639	0	0	0	0	0	0	0	0
307	V1980	4,176,066	1,842,156	2,333,910	81,892	83,005	-3,581	0	0	0	0	0	0	0	0
308	V1981	1,531,635	1,531,634	1	37,539	242,877	-4,827	0	0	0	0	0	0	0	0
309	V1982	1,251,080	1,220,094	30,987	62,554	255,575	8,167	0	0	0	0	0	0	0	0
310	V1983	680,074	634,794	45,280	34,004	83,103	726	0	0	0	0	0	0	0	0
311	V1984	7,890,634	6,804,609	1,086,026	394,532	-323,636	86,993	0	0	0	0	0	0	0	0
312	V1985	5,781,157	4,219,429	1,561,729	289,058	728,060	33,723	0	0	0	0	0	0	0	0
313	V1986	2,580,526	1,664,782	915,744	108,382	270,123	7,828	0	0	0	0	0	0	0	0
314	V1987	2,248,255	666,029	1,582,226	71,380	-4,765	-1,230	5,533	-177	-9,729	438	1,215	-43	-2,151	97
315	V1988A	1,906	1,029	876	90	170	9	13	0	-13	1	3	0	-3	0
316	V1988	5,282,223	1,376,692	3,905,531	167,684	-15,345	-2,862	39,183	-1,253	-43,379	1,862	8,601	-307	-9,589	412
317	V1989	4,544,115	1,035,084	3,509,032	144,270	-122,836	-15,219	30,157	-1,226	-51,723	2,127	6,608	-300	-11,434	470
318	V1990	12,041,420	2,336,826	9,704,594	382,315	-193,230	-22,894	84,313	-3,055	-185,624	7,313	18,491	-749	-41,034	1,617
319	V1991	1,238,702	200,948	1,037,754	39,329	-7,001	-389	12,280	-382	-14,162	537	2,696	-94	-3,131	119
320	V1992	12,759,837	1,687,158	11,072,679	405,125	-471,124	-94,323	171,338	-9,257	-220,809	8,079	37,431	-2,269	-48,811	1,786
321	V1993	6,304,381	744,933	5,559,447	200,164	-174,008	-46,587	66,899	-3,595	-87,429	3,148	14,616	-881	-19,327	696
322	V1994	888,775	46,527	842,248	22,788	-25,752	-8,839	0	0	0	0	0	0	0	0
323	V1995	3,940,851	147,872	3,792,978	101,043	-24,518	-15,179	25,489	-1,021	-52,728	1,405	7,139	-286	-14,817	395
324															
325		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
326		98,763,852	43,399,516	55,364,336	3,016,400	655,381	-98,340	435,205	-19,967	-665,596	24,910	96,799	-4,929	-150,296	5,591
327		===========	===========	===========	===========	===========	===========	===========	===========	===========	========	========	========	========	========
328															
329															
330															
331															
332															
333															
334															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1 2 3 4 5 6	VINTAGE	Tax Bases	Tax Reserve	Net	Allowable Tax Depn 1996	Federal Deferred Tax Assoc. w Depn	1996 Deferred Taxes	Federal Deferred Taxes Assoc W AFUDC Debt	1996 Deferred Taxes AFUDC Debt	Federal Deferred Tax Assoc w Avoided AFUDC	1996 Deferred Taxes Avoided AFUDC	State Deferred Taxes Assoc w AFUDC Debt	1996 Deferred Taxes AFUDC Debt	State Deferred Taxes Assoc W Avoided AFUDC	1996 Deferre Taxes Avoided AFUDC
335	***Salem Plant***														
336	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
337	V1974	0	0	0	0	-238	0	0	0	0	0	0	0	0	0
338	V1976	271,600,643	269,970,290	1,630,353	126,945	603,464	-3,515,898	0	0	0	0	0	0	0	0
339	V1977	7,346,303	7,257,174	89,129	5,045	108,035	-148,589	0	0	0	0	0	0	0	0
340	V1978	10,646,386	10,051,115	595,271	29,823	-50,263	-178,996	0	0	0	0	0	0	0	0
341	V1979	21,935,637	21,782,339	153,298	25,264	772,981	-493,223	0	0	0	0	0	0	0	0
342	V1980	20,144,911	19,507,004	637,907	98,306	1,198,397	-390,482	0	0	0	0	0	0	0	0
343	V1981	10,305,484	10,305,481	3	2,804	2,279,771	-116,943	0	0	0	0	0	0	0	0
344	V1982	23,191,005	23,188,821	2,184	17,126	4,457,119	-277,965	0	0	0	0	0	0	0	0
345	V1983	39,753,254	39,134,226	619,028	377,015	8,709,556	-342,845	0	0	0	0	0	0	0	0
346	V1984	21,458,139	21,221,779	236,360	93,235	3,987,311	-206,870	0	0	0	0	0	0	0	0
347	V1985	17,991,354	17,991,354	0	0	3,922,969	-211,394	0	0	0	0	0	0	0	0
348	V1986	14,046,954	14,034,161	12,792	3,198	2,845,960	-180,275	0	0	0	0	0	0	0	0
349	V1987A	16,050,116	16,050,115	1	1,444,509	3,645,769	306,258	126,108	-4,260	-238	1,420	27,672	-1,044	-53	314
350	V1987	8,942,115	6,066,206	2,875,909	522,893	1,022,313	63,334	48,807	-1,786	-2,066	339	10,703	-438	-457	75
351	V1988A	5,865,791	5,319,731	546,060	525,813	1,073,869	97,562	18,076	-730	-14,697	14,437	3,961	-179	-3,249	3,191
352	V1988	18,801,902	12,158,324	6,643,578	1,015,656	1,612,159	62,291	49,594	-2,322	-106,801	16,353	10,852	-569	-23,609	3,615
353	V1989	31,488,281	17,879,478	13,608,803	1,817,911	3,435,669	254,272	54,284	-1,672	-298,359	39,256	11,920	-410	-65,954	8,678
354	*V1990*	*37,133,163*	*18,208,769*	*18,924,394*	*2,045,041*	*3,427,823*	*287,700*	*299,679*	*-9,157*	*-481,263*	*52,139*	*65,806*	*-2,244*	*-106,387*	*11,526*
355	V1991	32,236,069	14,331,863	17,904,206	1,994,127	2,416,135	269,548	417,757	-14,571	-509,124	58,554	91,648	-3,571	-112,545	12,944
356	V1992	48,641,691	19,180,971	29,460,720	3,432,631	3,565,239	491,698	482,037	-18,128	-508,508	59,091	105,687	-4,443	-112,409	13,063
357	V1993	65,019,494	20,920,012	44,099,482	5,075,313	3,965,505	789,014	2,203,176	-81,558	-2,323,294	274,665	483,110	-19,988	-513,581	60,717
358	V1994	42,800,642	10,432,817	32,367,825	3,750,674	1,934,446	619,097	1,322,525	-50,893	-1,471,804	184,992	289,909	-12,473	-325,353	40,894
359	V1995	31,433,545	4,952,288	26,481,257	3,220,260	720,917	472,174	809,074	-51,906	-1,192,060	168,960	226,606	-14,538	-334,986	47,480
360															
361		--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
362		796,832,877	599,944,318	196,888,559	25,623,587	55,654,908	-2,350,532	5,831,117	-236,983	-6,908,215	870,206	1,327,874	-59,896	-1,598,583	202,496
363		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
364															
365															
366															
367															
368															
369															
370															
371															
372															
373															
374															
375															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1								Federal		Federal		State		State	
2						Federal		Deferred	1996	Deferred	1996	Deferred	1996	Deferred	1996
3					Allowable	Deferred Tax		Taxes	Deferred	Tax	Deferred	Taxes	Deferred	Taxes	Deferre
4	VINTAGE	Tax Bases	Tax Reserve	Net	Tax	Assoc.	1996 Deferred	Assoc W	Taxes	Assoc	Taxes	Assoc	Taxes	Assoc W	Taxes
5					Depn 1996	w Depn	Taxes	AFUDC	AFUDC	w Avoided	Avoided	w AFUDC	AFUDC	Avoided	Avoided
6								Debt	Debt	AFUDC	AFUDC	Debt	Debt	AFUDC	AFUDC
376	**Electric Intangible Plant**														
377	-------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
378	V1950	74,764,297	0	74,764,297	0	0	0	0	0	0	0	0	0	0	0
379		------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
380		74,764,297	0	74,764,297	0	0	0	0	0	0	0	0	0	0	0
381		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
382															
383	**Limerick Disallowance**														
384	-------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
385	V1950	-527,419,706	0	-527,419,706	0	0	0	0	0	0	0	0	0	0	0
386	V1985	343,462,835	343,462,835	0	0	0	0	0	0	0	0	0	0	0	0
387															
388		------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
389		-183,956,871	343,462,835	-527,419,706	0	0	0	0	0	0	0	0	0	0	0
390		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
391	Steam Production Nondepreciable														
392	-------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
393	V1950	9,153,458	0	9,153,458	0	0	0	0	0	0	0	0	0	0	0
394															
395		------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
396		9,153,458	0	9,153,458	0	0	0	0	0	0	0	0	0	0	0
397		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
398	**Salem Non Depreclalbe**														
399	-------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
400	V1950	75,626	0	75,626	0	0	0	0	0	0	0	0	0	0	0
401															
402		------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
403		75,626	0	75,626	0	0	0	0	0	0	0	0	0	0	0
404		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
405	**Limerick Non Depreclalbe**														
406	-------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
407	V1950	7,903,504	0	7,903,504	0	0	0	0	0	0	0	0	0	0	0
408															
409		------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------	------------
410		7,903,504	0	7,903,504	0	0	0	0	0	0	0	0	0	0	0
411		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
412															
413															
414															
415															
416															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1								Federal		Federal		State		State	
2						Federal		Deferred	1996	Deferred	1996	Deferred	1996	Deferred	1996
3					Allowable	Deferred Tax		Taxes	Deferred	Tax	Deferred	Taxes	Deferred	Taxes	Deferre
4	VINTAGE	Tax Bases	Tax Reserve	Net	Tax	Assoc.	1996 Deferrec	Assoc W	Taxes	Assoc	Taxes	Assoc	Taxes	Assoc W	Taxes
5					Depn 1996	w Depn	Taxes	AFUDC	AFUDC	w Avoided	Avoided	w AFUDC	AFUDC	Avoided	Avoided
6								Debt	Debt	AFUDC	AFUDC	Debt	Debt	AFUDC	AFUDC
417	**Peach Bottom Non Depreciable**														
418	--------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
419	V1950	3,427,032	0	3,427,032	0	0	0	0	0	0	0	0	0	0	0
420		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
421		3,427,032	0	3,427,032	0	0	0	0	0	0	0	0	0	0	0
422		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
423	**Hydraulic Non Depreciation**														
424	--------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
425	V1950	1,420,823	0	1,420,823	0	0	0	0	0	0	0	0	0	0	0
426		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
427		1,420,823	0	1,420,823	0	0	0	0	0	0	0	0	0	0	0
428		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========
429	**Transmission and Distribution Non Deprecible**														
430	--------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
431	V1950	88,415,610	0	88,415,610	0	0	0	0	0	0	0	0	0	0	0
432		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
433		88,415,610	0	88,415,610	0	0	0	0	0	0	0	0	0	0	0
434		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	
435	**Electric General Plant Non Depreciable**														
436	--------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
437	V1950	2,109,928	0	2,109,928	0	0	0	0	0	0	0	0	0	0	0
438		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
439		2,109,928	0	2,109,928	0	0	0	0	0	0	0	0	0	0	0
440		==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	==========	

Attachment FG-6

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)

	September 30, 1996 (Unaudited)	December 31, 1995
ASSETS		
UTILITY PLANT		
Plant at Original Cost	$ 14,895.2	$ 14,696.0
Less Accumulated Provision for Depreciation	4,975.9	4,623.7
	9,919.3	10,072.3
Nuclear Fuel, Net	163.7	191.1
Construction Work in Progress	611.2	494.2
Leased Property, Net	189.1	180.4
	10,883.3	10,938.0
CURRENT ASSETS		
Cash and Temporary Cash Investments	60.8	20.6
Accounts Receivable, Net		
Customer	51.2	75.2
Other	56.2	72.0
Inventories, at Average Cost		
Fossil Fuel	78.4	78.3
Materials and Supplies	118.8	123.4
Deferred Energy Costs	78.5	55.9
Other	117.6	60.8
	561.5	486.2
DEFERRED DEBITS AND OTHER ASSETS		
Recoverable Deferred Income Taxes	1,988.4	2,077.4
Deferred Limerick Costs	374.2	390.4
Deferred Non-Pension Postretirement Benefits Costs	237.1	248.1
Investments	409.5	318.4
Loss on Reacquired Debt	289.8	308.6
Other	158.1	193.5
	3,457.1	3,536.4
TOTAL	$ 14,901.9	$ 14,960.6

See Notes to Condensed Consolidated Financial Statements

(Continued)

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)

	September 30, 1996 (Unaudited)	December 31, 1995
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common Shareholders' Equity		
Common Stock (No Par)	$ 3,517.5	$ 3,506.3
Other Paid-In Capital	1.3	1.3
Retained Earnings	1,113.4	1,023.7
Preferred and Preference Stock		
Without Mandatory Redemption	199.4	199.4
With Mandatory Redemption	92.7	92.7
Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership	302.2	302.3
Long-Term Debt	4,185.8	4,198.3
	9,412.3	9,324.0
CURRENT LIABILITIES		
Notes Payable	281.7	-
Long-Term Debt Due Within One Year	54.2	401.0
Capital Lease Obligations Due Within One Year	60.3	60.3
Accounts Payable	179.8	299.7
Taxes Accrued	106.5	107.6
Deferred Income Taxes	22.6	17.1
Interest Accrued	88.9	88.0
Dividends Payable	30.3	20.7
Other	85.2	82.8
	909.5	1,077.2
DEFERRED CREDITS AND OTHER LIABILITIES		
Capital Lease Obligations	128.8	120.1
Deferred Income Taxes	3,326.5	3,312.6
Unamortized Investment Tax Credits	340.6	351.6
Pension Obligation for Early Retirement Plans	216.3	216.3
Non-Pension Postretirement Benefits Obligation	332.6	326.3
Other	235.3	232.5
	4,580.1	4,559.4
COMMITMENTS AND CONTINGENCIES (NOTE 5)		
TOTAL	$ 14,901.9	$ 14,960.6

See Notes to Condensed Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(Millions of Dollars)

	9 Months Ended September 30,	
	1996	1995
CASH FLOWS FROM OPERATING ACTIVITIES		
NET INCOME	$ 398.9	$ 489.9
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	404.2	390.1
Deferred Income Taxes	106.9	109.0
Gain on Sale of Subsidiary	-	(58.7)
Deferred Energy Costs	(22.6)	(35.4)
Changes in Working Capital:		
Accounts Receivable	39.8	(25.3)
Inventories	4.5	(45.1)
Accounts Payable	(119.9)	(71.9)
Other Current Assets and Liabilities	(54.6)	36.3
Other Items Affecting Operations	87.0	35.1
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	844.2	824.0
CASH FLOWS FROM INVESTING ACTIVITIES		
Investment in Plant	(365.6)	(353.2)
Proceeds from Sale of Subsidiary	-	150.0
Increase in Investments	(91.1)	(23.4)
NET CASH FLOWS USED BY INVESTING ACTIVITIES	(456.7)	(226.6)
CASH FLOWS FROM FINANCING ACTIVITIES		
Change in Short-Term Debt	281.7	(11.5)
Issuance of Common Stock	11.2	8.7
Issuance of Long-Term Debt	35.6	-
Retirement of Long-Term Debt	(397.5)	(184.7)
Loss on Reacquired Debt	18.8	14.5
Dividends on Preferred and Common Stock	(306.9)	(287.7)
Change in Dividends Payable	9.6	12.4
Other Items Affecting Financing	0.2	2.5
NET CASH FLOWS USED BY FINANCING ACTIVITIES	(347.3)	(445.8)
INCREASE IN CASH AND CASH EQUIVALENTS	40.2	151.6
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	20.6	47.0
CASH AND CASH EQUIVALENTS AT END OF PERIOD	60.8	198.6

See Notes to Condensed Consolidated Financial Statements

Exhibit 8

Form of Notice

PECO ENERGY COMPANY REQUESTS PaPUC APPROVAL OF A RATE DECREASE IN PREPARATION FOR ELECTRIC COMPETITION

The Pennsylvania Legislature recently passed and Governor Ridge signed a law that will begin to allow customers to choose their electric generation supplier by 1999 with all customers provided choice by 2001. That law provides utilities the opportunity to seek recovery of certain transition costs and to refinance some of their property, passing the savings associated with refinancing on to customers in the form of reduced rates.

PECO Energy has filed with the Pennsylvania Public Utility Commission (PaPUC) to refinance approximately $3.6 billion of such property (plus associated costs of refinancing.) Subject to PaPUC approval, this amount of refinancing will result in an estimated $95 million overall decrease in customer rates, or approximately 2.9%, depending on market interest rates at the time of the refinancing. The monthly bill for a typical residential customer using 500 kWh would decrease by $1.93, or 2.7%.

For more information contact PECO Energy at 1-800-494-4000. You may contact the PaPUC at P. O. Box 3265, Harrisburg, Pennsylvania, 17105-3265 within 15 days of receipt of this notice if you wish to file a complaint or participate in the proceedings.

PECO Energy Company

January/February 1997