ORIGINAL

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

R-00973953

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

Exhibit 1
VOLUME V

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PA PUBLIC UTILITY COMMISSION
PROTHONOTARY'S OFFICE

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APPLICATION OF PECO ENERGY COMPANY
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DIRECT TESTIMONY OF

JAMES I. WARREN

Regarding The Principles Governing PECO Energy Company's Treatment Of Deferred Federal Income Taxes, FAS 109 Assets And Liabilities And Deferred Investment Tax Credits In Its Quantification Of Stranded Investment

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TABLE OF CONTENTS

ORIGINAL

DIRECT TESTIMONY OF JAMES I. WARREN

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James I. Warren. My business address is 40 West 57th Street, New York, New York 10019.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a partner in the law firm of Reid & Priest.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES AT REID & PRIEST AND YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. A description of my responsibilities and my professional and educational background is appended as Exhibit JIW-1.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe and explain the principles which govern PECO Energy Company's ("PECO" or the "Company") treatment of: (1) accumulated deferred federal income taxes ("ADFIT"), (2) regulatory assets and liabilities associated with accounting for income taxes under FAS 109 ("FAS 109 assets and liabilities") and (3) accumulated deferred investment tax credits ("ADITC") in its quantification of its stranded costs. I shall then discuss the way in which those principles are reflected in the Company's filing. I shall address these areas primarily on a conceptual basis. Mr. Alan Cohn's testimony will describe the particulars of the Company's filing in significantly greater detail.

Q. WILL YOU SUMMARIZE YOUR TESTIMONY?

A. My testimony is divided into two sections, the first dealing with ADFIT and FAS 109 assets and liabilities and the second addressing ADITC. With respect to ADFIT, it is my testimony that this balance represents a liability due to the federal government which requires funding through the rate process. With respect to FAS 109 assets and liabilities, it is my testimony that the net asset balance represents the proper and equitable means by which the ADFIT amounts due the government must be funded. They, therefore, constitute a legitimate and necessary component of PECO's stranded investment and should be included in full in its quantification. The second section of my testimony addresses ADITC. With respect to ADITC, it is my testimony that this balance is properly reflected as a reduction in stranded investment only after being discounted.

III. ADFIT AND FAS 109 ASSETS AND LIABILITIES

Q. WHAT ARE THE FUNDAMENTAL PRINCIPLES THAT GOVERN THE TREATMENT OF ADFIT AND FAS 109 ASSETS AND LIABILITIES?

A. There are two principles of fundamental importance. The first has to do with the way in which federal income taxes impact the ratemaking process and the second with the nature of deferred taxes.

Q. PLEASE STATE THE FIRST PRINCIPLE?

A. The first principle is that, in our 35% federal income tax rate environment, in order to fund $1 of federal income tax expense, PECO must receive revenues of approximately $1.54. This is because PECO's revenues are fully taxable and, unlike the situation with salary, fuel and most other expenses incurred by PECO, federal income taxes are not deductible. Thus, there is no deduction to offset the taxable revenue. After receiving $1.54 of revenue and paying a $.54 federal income tax on this receipt, PECO will have $1 left with which to pay its tax.

Q. IS THIS SITUATION PECULIAR TO PECO OR TO PUBLIC UTILITIES IN GENERAL?

A. No. It is true of every corporate enterprise. GM, Microsoft and Walmart must each receive the same $1.54 in revenues to fund $1 of their federal income tax expense as must PECO.

Q. DOES IT MATTER WHETHER THE TAX EXPENSE IS CURRENTLY PAYABLE OR PAYABLE IN THE FUTURE?

A. No it doesn't. The distinction between a current and future (*i.e.*, deferred) tax, as will be described in greater detail hereafter, is only in the timing of the payment of the tax to the government. It has no effect whatsoever on the ***amount*** that must be received from customers to fund that payment. Both PECO and Walmart must receive the same $1.54 to fund either a currently payable or a future tax.

Q. DOES THE AMOUNT OF REVENUE NEEDED TO FUND A GIVEN LEVEL OF TAX DEPEND AT ALL ON WHETHER THE COMPANY PRACTICES NORMALIZATION OR FLOW THROUGH RATEMAKING?

A. No. The difference between normalization and flow through ratemaking relates only to ***when*** a given level of tax expense will be funded through the rate process, not to ***how much*** must be received to fund the tax. Thus, the ratemaking method employed is entirely irrelevant to the "gross up" principle set forth above. If normalization is practiced, the Company may charge the $1.54 in advance of its payment of the $1 tax to the government. If flow through is practiced, then the $1.54 will be charged only contemporaneously with the $1 tax payment to the government. In either case, the customers must be charged the same amount ($1.54) to fund the same level of tax ($1).

Q. WHAT IS THE SECOND PRINCIPLE?

A. The second principle is that a deferred federal income tax constitutes the economic equivalent of an interest-free loan from the federal government. This is most clearly illustrated by examining the operation of accelerated tax depreciation, the item which generally produces most deferred taxes. With respect to any depreciable asset, a loan is extended as the Company claims tax depreciation which exceeds its book (*i.e.*, economic) depreciation. This generally occurs as the Company claims accelerated tax depreciation on its tax return in the early years of the asset's productive life. The loan is "repaid" as the Company's book depreciation exceeds its tax depreciation. Deferred taxes therefore represent the necessity to pay an amount to the government in the future.

Q. DOES THE EXISTENCE OF THE LOAN DEPEND ON WHETHER THE COMPANY PRACTICES NORMALIZATION OR FLOW THROUGH RATEMAKING?

A. No. The interest-free loan is extended to the Company as it claims accelerated depreciation on its tax return. It is in no way dependent on the ratemaking process. General Motors, IBM and most other American enterprises, regulated or not, receive loans of this type. The availability of the loan is a matter between the company and the government. The ratemaking process only impacts the timing of the receipt by the utility of the wherewithal to repay the loan.

Q. HOW IS THIS REFLECTED IF THE COMPANY'S REGULATORS PERMIT NORMALIZED RATEMAKING?

A. If the Company's regulators permit normalized ratemaking, it retains the governmental loan proceeds and is, therefore, responsible for its eventual repayment out of its own resources. The reflection of this obligation takes the form of a deferred tax credit. To follow through the simple example, the Company would receive $1.54 in rates for each $1 of its tax expense, including its deferred tax expense. It would pay $.54 in tax on the receipt of this amount and record a $1 deferred tax. The $1 could then be used in its business operations until such time as it was required to be paid back to the government.

Q. HOW IS THIS REFLECTED IF THE COMPANY'S REGULATORS REQUIRE FLOW THROUGH RATEMAKING?

A. If the Company's regulators require flow through ratemaking, then it "flows through" the governmental loan proceeds to its customers. The "flow through" occurs through the rate process and reduces rates by $1.54 for each $1 of governmental loan. The Company remains, nevertheless, responsible for the eventual loan repayment. However, instead of repaying the loan out of its own resources, there exists the implicit regulatory promise that, when the governmental loan comes due, the customers will "flow back" to the Company through the rate process the governmental loan proceeds they previously received to enable liquidation of the debt. Just as they received a $1.54 rate reduction for each $1 of loan proceeds "flowed through" to them, the "flow back" of those proceeds will require that they be charged $1.54 for each $1 of loan repayment they are funding.

Q. HOW DOES FAS 109 REQUIRE THE COMPANY TO REFLECT THE FLOW THROUGH SITUATION?

A. In the year of flow through, under FAS 109 the Company must reflect its responsibility to the government by recording a deferred tax liability of $1. It also reflects the implicit promise by the customers to pay $1.54 when they "flow back" the loan proceeds. Finally, it records the $.54 tax it will pay when it receives this $1.54 "flow-back" proceeds as an additional deferred tax liability. It is critical to note that when the loan needs to be repaid, the Company must collect $1.54. If it does so, it will pay the $.54 tax on the receipt of the revenues and will have the remaining $1 to repay the loan. It will be neither benefitted nor damaged. If it receives anything less than $1.54, it will be harmed.

Q. DO NON-REGULATED COMPANIES DIFFER FROM UTILITIES IN TERMS OF THE TWO PRINCIPLES DISCUSSED ABOVE?

A. In most respects they do not. Non-regulated enterprises must fund all of their taxes (both current and deferred) out of revenues received from their customers. In this regard, they are no different from regulated companies. Moreover, like utilities, they must produce revenues of $1.54 to pay a $1 federal tax liability (again, whether it is current or deferred). Finally, they are extended governmental loans just as utilities are.

Q. IN WHAT WAY ARE NON-REGULATED COMPANIES DIFFERENT FROM REGULATED ONES?

A. Under the special accounting rules of FAS 71, regulated enterprises can "flow through" the proceeds of a governmental loan to customers and offset the adverse effect of the lower revenues by recording as a regulatory asset the promise on the part of regulators to increase rates at a later date to "flow back" the amount. This obligation assumes the form of a FAS 109 asset. It is the recordation of this promise that reflects the opportunity afforded the utility to earn its allowed rate of return even though one of its economic costs, deferred taxes, is not being currently funded. Thus, a regulated enterprise can defer the collection of its $1.54 for each $1 of deferred tax in the year the governmental loan is extended until a later time without negatively impacting earnings.

Non-regulated enterprises have no such flexibility. They are unable to establish the regulatory FAS 109 assets which utilities can establish. As a consequence, if a non-regulated enterprise "flows through" the proceeds of a governmental loan to its customers in the year it is extended, its net income is diminished. It has not covered its economic costs (*i.e.*, deferred taxes) - even if it has covered its cash costs (*i.e.*, currently payable taxes). Thus, utilities are unique in the flexibility the accounting rules afford their treatment of tax expense.

Q. WILL YOU PROVIDE A SIMPLE EXAMPLE OF HOW THESE TWO PRINCIPLES INTERACT WITH ONE ANOTHER?

A. Yes. Assume that all of Utility Corporation's ("U") items of income and expense save for depreciation are treated identically for book and tax purposes. U's costs, other than depreciation are $800. Its permitted return (all equity) is $100. Assume further that U owns an asset costing $600 which has a 3 year book life and a 2 year tax life. U's governmental loan posture looks as follows:

YEAR	BOOK DEPRECIATION	TAX DEPRECIATION	LOAN EXTENDED	TOTAL LOAN OUTSTANDING
1	200	300	35	35
2	200	300	35	70
3	200	0	(70)	0

As the matrix above indicates, U borrows from the government in the first two years ($35 each year) and repays the aggregate loan ($70) in the third year.

Q. DOES THE EXTENSION OF THE LOAN HAVE ANYTHING WHATSOEVER TO DO WITH THE RATEMAKING PROCESS?

A. No it does not. This pattern of borrowing and repayment would occur regardless of how U treats its taxes in the ratemaking process. It is entirely a matter between the federal government and U.

Q. OF WHAT RELEVANCE IS RATEMAKING, THEN?

A. While ratemaking does not impact the existence of the loan, it does determine (1) what will be done with the proceeds of the loan and (2) where the resources will come from to repay the loan when it becomes due. This principle is illustrated in the examples which follow.

Q. HOW WOULD RATES BE SET UNDER THESE CIRCUMSTANCES IF U'S REGULATORS PERMIT NORMALIZED RATEMAKING?

A. If U's regulators permit normalized ratemaking and rates are reset in each year, then in each year, U's rates are set to allow it the opportunity to recover (a) its book costs ($800 plus $200 depreciation), (b) the tax consequences of book levels of items of income and expense and (c) its after-tax equity return of $100. Rates are, therefore, set at $1,154. If all occurs as anticipated, the following results to U ensue:

Revenues	$1,154
Expenses	(800)
Book Depreciation	(200)
Pre-tax Income	$154
Tax Expense (35%)	(54)
Net Income	$100

Q. WHAT WILL U'S TAX RETURN LOOK LIKE?

A. In each of the first two years, U's tax return looks as follows:

Revenues	$1,154
Expenses	(800)
Tax Depreciation	(300)
Taxable Income	$54
Tax Return Tax (35%)	$19

U has a currently payable tax liability of $19. The difference between this amount and U's total tax expense of $54 is its deferred tax liability of $35. This is the amount of the governmental loan extended in each of those years by virtue of being able to claim $100 more tax depreciation than economic depreciation.

Q. UNDER NORMALIZATION RATEMAKING, WHAT HAPPENS TO THE LOAN PROCEEDS?

A. Under normalization ratemaking, U retains the loan proceeds and can use this amount to finance its operations. The existence of this zero-cost loan would be recognized in the ratemaking process. Deferred tax balances are employed to reduce regulated rate base. Thus, customers are not charged a return on rate base which is financed by these governmental loans. In this way, the full financial benefit of the zero-cost loans is provided to customers.

Q. HOW WOULD RATES BE SET IF U'S REGULATORS REQUIRE FLOW THROUGH RATEMAKING?

A. If U's regulators require flow through ratemaking, rates are set so as to permit U to recover (a) its book costs ($800 plus $200 depreciation), (b) the tax currently due (*i.e.*, not based on book items of income and expense but tax items of income and expense) and (3) its after-tax equity return of $100. Thus, in the first two years, rates are set at $1,100. U's tax return appears as follows:

Revenues	$1,100
Expenses	(800)
Tax Depreciation	(300)
Taxable Income	$0
Tax Return Tax	$0

U's income statement for those years appears as follows:

Revenues	$1,100
Expenses	(800)
Book Depreciation	(200)
Pre-tax Income	$100
Tax Return Tax	(0)
Net Income	$100

Note that flow through rates (*i.e.*, revenues) are less than normalized rates by $54. This reduction represents the rate effect of "flowing through" the benefit of the $35 governmental loan. The amount of the loan is "grossed up" as previously described. However, the loan still exists, notwithstanding the fact that its benefit was "flowed through" to customers and U is still responsible for its repayment. FAS 109 reflects this by requiring U to reflect the $35 governmental loan as a deferred tax. However, FAS 71 also permits U to reflect a FAS 109 asset for the $54 the customers will pay back to the company when the loan becomes due. Finally, U must reflect as an incremental deferred tax the income tax it will be assessed upon the receipt of that $54 ($54 x 35% or $19).

At the end of Year 2, the governmental loan portion of U's deferred tax balance will equal $70. Its FAS 109 asset balance, the future revenue necessary to fund the loan repayment, will equal $108. Finally, U will reflect as an additional deferred tax liability the $38 tax cost of receiving the future revenue.

Q. WHAT HAPPENS IN THE FLOW THROUGH SITUATION IN YEAR 3?

A. In Year 3, rates must be set $108 higher than they would on a normalized basis to effect a restoration by customers of the loan proceeds they previously received. U's tax return would appear as follows:

Revenues	$1,262
Expenses	(800)
Tax Depreciation	(0)
Taxable Income	$462
Tax Return Tax (35%)	$162

U's financial statement would appear as follows:

Revenues	$1,262
Expenses	(800)
Book Depreciation	(200)
Pre-tax Income	$262
Tax Return Tax	(162)
Net Income	$100

Q. WHAT WILL HAPPEN IF U DOES NOT RECEIVE THE $108 IN REVENUES WHICH REPRESENTS THE RESTORATION OF THE LOAN PROCEEDS?

A. By the end of Year 2, the asset will have been fully depreciated for tax purposes. Thus, U will be able to claim no depreciation on its tax return in Year 3. This situation is in no way impacted by ratemaking. The fact is that U will be compelled to repay the $70 governmental loan through its tax liability for Year 3. If U receives even $1 less than the necessary $108 of incremental revenues, it will not have received the amount necessary to fund the repayment.

Q. WHAT DOES THIS ILLUSTRATE REGARDING THE IMPORTANCE OF RECOVERING THE COMPANY'S FAS 109 ASSETS?

A. This illustrates the critical importance that PECO's FAS 109 assets be recovered in full. Recovery is necessary to fund the repayment of governmental loans. Any compromise would cause the Company's shareholders to bear the cost of a tax advantage which was previously provided not to the Company, but to its customers.

Q. WILL YOU SUMMARIZE THE NATURE OF AND THE RELATIONSHIP BETWEEN ADFIT AND FAS 109 ASSETS?

A. The Company's ADFIT balance reflects an amount that must eventually be paid to the government. This is the amount of the governmental loan to the Company. This is its character whether the ADFIT was recorded under conventional regulatory principles or due to the operation of FAS 109. In either case, the liability will be triggered when the assets reflected on the Company's balance sheet produce cash flows equal to their carrying value. At that time, the liquidation of the liability will represent a cash outflow to the government. This is not a payment that will go to customers. Because it is a governmental liability, it cannot be extinguished, diminished or otherwise altered by regulatory action.

The Company's FAS 109 asset reflects the promise by the regulators to fund the eventual governmental loan repayment when it becomes due. Again, it reflects, as it must, a "tax gross up" so that the Company will have the wherewithal to pay the amount due the government.

As described above, the Company's "creditor" is the government and its "debtor" is its customers. Thus, the debtor and creditor are not the same. This is not a situation where the Company is owed money by someone to whom it owes money. Thus, the liability and the receivable cannot be rationally netted. The situation is analogous to that of an employee who has a mortgage on his house and who is owed a week's wages by his employer. Notwithstanding that the wages will be used to pay down the mortgage (after the payment of income taxes), there is no conceivable way that the employer should be permitted to reduce its obligation to the employee due to the existence of the mortgage obligation. No rational person could support such a proposition. So it is with the Company's FAS 109 assets. These represent the source from which the governmental loans will be repaid. No netting is supportable.

Q. WHY IS THE FAS 109 ASSET BALANCE COMPUTED ON A "GROSSED UP" BASIS WHILE THE ADFIT BALANCE IS NOT?

A. The ADFIT balance represents an amount due to the government. Since its payment to the government will produce no tax benefit, no "gross up" is appropriate. If, instead, it represented a liability due to customers, its satisfaction (by means of a rate reduction) would produce a tax benefit. Under those circumstances, a "gross up" would be appropriate. However, that is not the case.

By contrast, the FAS 109 asset is the amount of fully taxable revenue necessary to fund the ADFIT. A "gross up" is not only permissible, it is a necessity.

It would be useful in this context to revisit the previously described hypothetical situation of the employee having a mortgage. The payment by the employee of the principle of his mortgage is not tax deductible. However, each dollar he earns to enable him to make that payment will be subjected to income tax. Thus, if the employee desires to pay off his mortgage, he needs to earn an amount equal to the "grossed up" amount of the debt. The "gross up" concept is applicable to his income but not to the mortgage liability. So it is here. The FAS 109 liability must be "grossed up" so that PECO will receive an amount sufficient to repay its governmental loans.

Q. WILL YOU ADDRESS THE ISSUE OF THE TIME VALUE BENEFIT OF ADFIT?

A. As previously indicated, ADFIT represents an interest-free loan from the government. Its benefit is, therefore, a time value benefit. In the conventional ratemaking process, this benefit is provided to customers by means of reflecting ADFIT as an offset to the rate base upon which customers are required to pay a return.

This proceeding will not eliminate governmental interest-free loans associated with stranded plant. However, it will prospectively eliminate rate of return computations which reflect stranded costs. Thus, in the normal course, there will be no ongoing mechanism to capture the beneficial effect of governmental loans in charges to customers. Customers should continue to receive the benefit of all interest-free loans that are associated with costs they are bearing. Insofar as they will fund stranded investments through the CTC, they are equitably entitled to the full measure of the benefit of any such loans associated with the costs they are bearing.

Q. WHAT ARE THE VARIOUS ELEMENTS OF SUCH TIME VALUE BENEFITS?

A. There are two components of tax-related time value benefits. The first relates to governmental loans already in place. The second relates to governmental loans that may be extended in the future. I will address each component individually.

Q. WHAT IS THE NATURE OF THE BENEFIT OF LOANS CURRENTLY IN PLACE?

A. The Company has a substantial existing balance of deferred taxes associated with its stranded investment. However, these balances will inexorably diminish. Once stranded costs become incorporated into the CTC, it is the amortization period of the CTC, and not the original depreciable life of the underlying assets, that governs the triggering of the necessity to repay the loan. In this regard, the effect is not unlike shortening an asset's depreciable life. Thus, whatever loans are currently outstanding will diminish over the CTC amortization period. At the end of that time, they will be extinguished. Thus, the value of the loans currently in place is equal to the present value of the use of an amount of cost-free capital that diminishes over the CTC amortization period.

Q. WHAT IS THE NATURE OF THE BENEFIT OF LOANS NOT YET EXTENDED?

A. The Company's stranded investment has significantly less tax basis than book basis (much, but not all, of the difference due to accelerated tax depreciation). However, these assets still retain a rather substantial amount of tax basis. This stranded investment tax basis will produce a stream of tax deductions in the future (*e.g.*, future accelerated depreciation claimed with respect to generating plant). These future deductions will produce at least some governmental loans similar to the ones already in place (which are evidenced by existing deferred tax balances). The net benefit of the use of the cost free capital during the time between the future extension of the governmental loans and their repayment must be valued and then reflected in the amounts customers are required to pay.

Q. HOW HAS THE COMPANY REFLECTED THIS LEVEL OF BENEFIT?

A. The Company has captured both of the time value benefits described above. The aggregate net present value of these benefits has been used to reduce the return required with respect to the stranded investment. By means of this mechanism, the Company's customers have been provided the full, true economic value of the availability of all present and future loans.

IV. ADITC

Q. WILL YOU DESCRIBE HOW THE COMPANY HAS TRADITIONALLY ACCOUNTED FOR ITS INVESTMENT TAX CREDITS (THE "CREDIT")?

A. Up until the end of 1985, the tax law awarded tax credits to taxpayers making enumerated types of investments. Over the years, the Company became entitled to these credits as a result of certain of its plant investments. The Company was able to use the credits earned to reduce the tax liability otherwise due. In the year in which a credit was used to reduce its currently payable tax, the Company did not reduce tax expense immediately. Instead, it recorded a deferred credit which had the effect of deferring the income statement benefit of credit utilization. It amortized the deferred credit as a reduction to the tax expense element of cost of service over the regulatory life of the asset producing the credit (as the asset was depreciated). Thus, customers received the benefit of the credit as they funded the asset over its life.

Q. WHAT DOES THE ADITC BALANCE REPRESENT AND HOW IS IT TREATED IN RATEMAKING?

A. The ADITC balance consists of the amount of credits claimed on tax returns which have not yet been passed through to customers. It represents cost-free capital, much like ADFIT does. Certainly the source, the federal government, is the same in both cases. However, unlike ADFIT, the ADITC benefit never has to be repaid to the government. Moreover, and again unlike ADFIT, in the calculation of rate base, ADITC has not been used as an offset. Thus, to the extent of its ADITC balance, Company shareholders have been able to earn a return on rate base supported by cost-free capital. The net economic result is that, in the case of ADITC, the customers benefit from the amortization of the credit and the shareholders benefit from the ability to earn on the unamortized balance (a balance which diminishes over the life of the asset). The benefits of the credit are, thus, shared.

Q. WHY HAS THE COMPANY ADOPTED THIS RATEMAKING APPROACH?

A. As a condition to accessing the benefit of the credit, the Internal Revenue Code ("Code") requires that a regulated public utility share the benefit of the credit between customers and shareholders. The rules that compel this are referred to as the Credit Normalization Rules. The Company's approach represents one of the two sharing mechanisms permitted by the Code.

Q. WHAT WOULD OCCUR IF THE CREDIT NORMALIZATION RULES WERE NOT COMPLIED WITH?

A. A failure to comply with the sharing requirement over the entire life of the asset will result in a recapture (*i.e.*, a repayment to the government) of the entire unamortized ADITC balance associated with all jurisdictional assets (not just the ADITC which is not properly shared).

Q. HOW HAS THE COMPANY DEALT WITH THE ADITC WHICH RELATES TO STRANDED GENERATING PLANT?

A. The Company has used this balance to offset the CTC charge, but only after discounting the amount. The discounting has the effect of providing to shareholders the time value of the ADITC balance. *In effect, it provides to them* something like the return they would have earned had the stranded investment remained in a rate base environment.

Q. WHY HAS THE COMPANY ADOPTED THIS APPROACH?

A. The Company has adopted this approach for two reasons. First and most significantly, this approach is consistent with a basic principle which has guided the Company in the formulation of its proposal regarding the treatment of taxes in this proceeding. In crafting its approach, the Company has used a "no harm, no foul" philosophy. It believed, and continues to believe, that the treatment of all parties should be consistent with historical treatment of each. This is evidenced by the careful attempt the Company has made to provide to customers the entire time value benefit of all deferred taxes - both present and future - associated with stranded investments. This is appropriate because the time value benefit is one customers have historically enjoyed. The Company has historically received a return benefit from its ADITC. To deprive it of this benefit in this proceeding would amount to "cherry picking" - carrying through the effects of those procedures that have historically benefitted the customers (*e.g.*, ADFIT time value benefits) but not those that have historically benefitted the Company. This is simply unfair.

Q. WHAT IS THE SECOND REASON FOR DISCOUNTING THE ADITC?

A. The second reason is that the Credit Normalization Rules may well mandate that the Company continue to earn a return on its ADITC. A failure to discount the ADITC amount could give rise to a violation of those rules and, hence, poses a very real risk to the Company and its customers.

Q. WILL YOU ELABORATE ON WHY YOU BELIEVE THIS RISK EXISTS?

A. There are two possible ways in which the IRS might view the treatment of stranded investment in this case from a Credit Normalization Rule perspective. It is possible that the IRS would take the view that the result of this proceeding is merely the designation of a level of stranded cost recovery and that such designation is beyond the purview of the Credit Normalization Rules because it has nothing to do with the benefits of credits claimed with respect to depreciable utility property. However, it is also possible that the IRS will view the computation of the CTC charge as merely the identification of specific costs (some of which have ADITC associated with them) to be recovered in a specifically designated fashion - through an CTC charge. In effect, a portion of the CTC may well be considered as utility plant costs which have been given another name and assigned a new life different from that of non-stranded plant costs. Under this view, because the underlying costs remain, the sharing requirement of the normalization rules would remain operative.

Q. IS IT YOUR OPINION THAT THE IRS MIGHT WELL ADOPT THE LATTER VIEW?

A. Yes it is.

Q. ON WHAT DO YOU BASE THIS OPINION?

A. I base my opinion on two factors.

Q. WILL YOU DESCRIBE THE FIRST FACTOR.

A. The first is a private letter ruling which the IRS National Office issued on February 27, 1988 and which was published as LTR 8922008. I have appended a copy of this ruling to my testimony as Exhibit JIW-2. The utility taxpayer in this ruling was required under the Credit Normalization Rules to treat its ADITC as a reduction to the tax expense element of cost of service ratably over the regulatory life of the plant that gave rise to the Credit (just as PECO does). The utility sold a plant upon which credits had been claimed and then leased it back. After engaging in this transaction, the utility no longer depreciated the plant for regulatory purposes over which to amortize the ADITC. It was, therefore, unsure how it should treat the unrecaptured ADITC associated with the plant consistent with the Credit Normalization Rules. It requested guidance from the

IRS National Office on this point. The National Office reasoned:

> Unlike the situation when public utility property is sold outright, in the sale-leaseback transaction the Utilities and their ratepayers continue to bear the cost of the property over the lease term. The regulated depreciation expense is simply replaced by a regulated rental expense. This is a critical factor in a determination of the proper treatment of the unamortized credits after the sale-leaseback transaction.

It concluded, therefore, that the utility's ADITC which related to the plant should be amortized by the utility over a period no shorter than the life of the lease.

Q. WILL YOU SUMMARIZE THE IMPORTANCE OF THIS CONCLUSION FOR THE CURRENT SITUATION?

A. In the ruling, the National Office concluded that the lease payments after the transaction were economically equivalent to the regulatory depreciation it had claimed with respect to the same plant before the transaction. If this "economic equivalence" rationale were applied to the current situation, it could support a continuation of the relevance of the Credit Normalization Rules.

Q. WHAT IS THE LEGAL STATUS OF PRIVATE LETTER RULINGS SUCH AS THE ONE YOU HAVE DESCRIBED?

A. A ruling such as the one described above is not precedential and is, therefore, not binding on the IRS (except with regard to the taxpayer to whom the ruling was issued). However, in the area of the application of the Credit Normalization Rules, there are very few authorities which enable practitioners to definitively ascertain the consequences of these rules for the many novel and creative regulatory proposals which have become prevalent. Thus, practitioners in the area routinely attempt to identify the rationales and approaches used by the IRS in such rulings to ascertain potential IRS positions in analogous situations. Even though non-precedential, these rulings serve as an important, if not actually the major, source of input regarding the application off the Credit Normalization Rules.

Q. WILL YOU DESCRIBE THE SECOND FACTOR SUPPORTING YOUR CONCLUSION?

A. In addition to the ruling described above, I have discussed this area with personnel in the IRS National Office on several recent occasions over the past few months. The discussions were held by telephone and did not involve a specific company nor a specific regulatory proposal (and, in fact, preceded this proceeding). These discussions convinced me that the IRS has not yet analyzed the issues raised by regulatory proceedings such as the instant one and has certainly not concluded what they believe to be the consequences under the Credit Normalization Rules.

Q. BASED ON THE ABOVE, WILL YOU RESTATE YOUR CONCLUSION REGARDING THE APPLICATION OF THE CREDIT NORMALIZATION RULES TO PECO'S SITUATION?

A. Based on the above, I have concluded that there exists a substantial risk that a failure to provide a return to the Company by discounting the ADITC would subject the Company to the severe sanctions imposed by the Credit Normalization Rules.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DESCRIPTION OF RESPONSIBILITIES AT REID & PRIEST AND PROFESSIONAL AND EDUCATIONAL BACKGROUND

I am engaged in the general practice of taxation. I specialize in the taxation of and the tax issues relating to regulated public utilities. The vast preponderance of my time is devoted to this specialty. As a part of my practice, I provide tax planning services to utilities, represent utilities in controversies with the Internal Revenue Service (the "IRS" or the "Service") and often assist them in procuring guidance from the IRS in the form of Private Letter Rulings and Technical Advice. Included in this area of specialization is the treatment of taxes in regulation.

I joined Reid & Priest in July of 1991. Prior to that time, I was a tax partner in the international accounting firm of Coopers & Lybrand. I served as that firm's National Director of Utility Taxation. At Coopers, I authored a course entitled "The Taxation of Regulated Public Utilities" and taught it extensively to Coopers accountants, utility companies and to several commission staffs. I also provided tax services directly to a number of electric, telephone, gas and water companies as well as to the United States Telephone Association (USTA). I consulted extensively with many of the Coopers offices throughout the country on utility tax matters.

I speak frequently before a wide variety of utility industry groups including various committees of the Edison Electric Institute (EEI), USTA and the American Gas Association (AGA) as well as at both the EEI and the AGA tax schools. For a number of years I have co-chaired the EXNET Public Utility Taxation conference and will be doing so again this October.

I have testified on several occasions at hearings conducted by the Internal Revenue Service and the Department of Treasury with respect to proposed tax regulations affecting utilities, before the House Ways and Means Committee with respect to tax legislation relevant to the utility industry, and before the Subcommittee on Select Revenue Measures of the Ways and Means Committee with respect to the withdrawal of certain proposed normalization regulations.

Additionally, I have provided testimony on a number of occasions before state regulatory commissions in Texas, Nevada, Florida, New York and New Jersey as well as the FERC regarding the operation of the tax law as well as the treatment of taxes in the setting of utility rates.

I graduated from Stanford University in 1971 with a Bachelor of Arts degree in Political Science. I then attended New York University School of Law from which I graduated in 1975 with a J.D. degree. After a judicial clerkship and two years of legal practice, in 1979 I received a Master of Laws degree (LL.M.) in taxation from New York University School of Law. In that same year, I commenced working for Coopers & Lybrand. In 1980, I received a Master of Science degree in accounting from New York University Graduate School of Business

Administration. I became certified by the State of New York to practice accountancy that same year.

I am a member of the New York and New Jersey Bars and, as previously mentioned, am a CPA licensed in New York. I am a member of the AICPA, a former chair of the Committee on Regulated Public Utilities of the American Bar Association, Section of Taxation and am currently Vice-Chair of the Accounting and Taxation Committee of the American Bar Association's Public Utility, Communications and Transportation Law Section.

Query: Private Letter Rulings:

PLR 8922008
Section 167

HEADNOTE:

Private Letter Ruling 8922008

Code Sec. 167 DEPRECIATION -- accelerated cost recovery system (ACRS) and modified accelerated cost recovery system (MACRS) -- sale-leaseback .

A consolidated group's parent owned two utilities, each of which was regulated by a state commission. In 1987, the utilities sold their interests in two facilities to a group of investors and, as part of the same transaction, leased back those interests. At the time of the sales, the utilities had unamortized accumulated deferred investment tax credits (ITC) and unamortized deferred tax reserves resulting from accelerated depreciation. The utilities were flow-through taxpayers in 1969 and continued to remain eligible for flow-through treatment for tax purposes. In 1975, the utilities elected to be subject to the ratable cost of service flow-through rules of Sec. 46(f)(2) for the additional 6% ITC. RULED: There are no restrictions on the state commissions' regulatory treatment, or the parent co.'s treatment in its regulated books of account, of the deferred gain or loss or of the deferred income taxes resulting from the sale-leaseback transaction. The IRS conditioned the ruling on the earlier deferred tax reserves being removed according to Reg. 1.167(1)-1(h)(2). There are no ratemaking or accounting limitations under Secs. 46(f)(1) and 46(f)(2) regarding the 4% portion of the unamortized ITC relating to the sale-leaseback property placed in service during 1975 through 1980. The IRS predicated the ruling on the parent co.'s having made a timely election under Sec. 46(f)(3) and Sec. 167(1)(2)(C)'s application to the property. RULED: The sale-leaseback property will remain public utility property after the transaction. The 6% portion of unamortized ITC relating to property placed in service during 1975 through 1980 and the unamortized ITC relating to property placed in service during 1981 and subsequent years may be ratably amortized on a straight-line basis over a period no shorter than the lease term. Finally, the The ITC available to the parent co. under Sec. 48(d) may be amortized in a similar fashion.

FULL TEXT:
February 27, 1988
0167.23-00

This is in reply to the letter from your representatives, dated March 31, 1988, wherein you have requested the following rulings:

1. There are no restrictions on the Commission's regulatory treatment, or the Taxpayer's treatment on its regulated books of account, of the deferred gain or loss (after adjustment for the deferred tax reserve resulting from accelerated depreciation) or of the deferred income taxes resulting from a sale-leaseback of the Facilities.

2. There are no ratemaking or accounting limitations under sections 48(f)(1) or 48(f)(2) of the Internal Revenue Code with respect to a four percent portion of unamortized investment credits relating to property, placed in service during the years 1975 through 1980, that is sold and leased back.

3. The 6 percent portion of unamortized investment credits relating to property placed in service during the years 1975 through 1980 that is sold and leased back, and the unamortized investment credits relating to property placed in service at Facility A during 1981 and subsequent years that is sold and leased back, can be ratably amortized on a straight-line basis over a period no shorter than the lease term to reduce cost of service for ratemaking purposes and on its regulated books of account.

4. The investment credit passed through to Utility B at Facility B under section 48(d) of the Internal Revenue Code can be ratably amortized on a straight-line basis over a period no shorter than the lease term to reduce cost of service for ratemaking purposes and on its regulated books of account.

Taxpayer has presented the facts as follows:

Taxpayer is a State A corporation under the audit jurisdiction of the Director of District A. Taxpayer is the parent corporation of a consolidated group that includes Utility A and Utility B.

Utility A, a State A corporation, is a regulated public utility under the audit jurisdiction of the Director of District A. Utility A is a member of the consolidated group of which the Taxpayer is the parent corporation. The Taxpayer owns all of the common stock of Utility A.

Utility B, a State A corporation, is a regulated public utility under the audit jurisdiction of the Director of District A. Utility B is a member of the consolidated group of which the Taxpayer is the parent corporation. The Taxpayer owns all of the common stock of Utility B.

Facilities A and B are both located in State B.

For purposes of section 167(l) of the Internal Revenue Code the Utilities were flow-through taxpayers in 1969 and continued to remain eligible for flow-through treatment for tax purposes. In 1972 the Utilities elected, under the predecessor to section 46(f)(3), to use immediate flow-through treatment of the four percent investment tax credit. In 1975 the Utilities elected to be subject to the ratable cost of service flow-through rules of section 46(f)(2) for the additional six percent investment tax credit.

The Commission required flow-through treatment of tax depreciation benefits until * * * In * * * Utility A was allowed normalization for property additions related to the * * * vintage year and future years. In * * * Utility B was allowed normalization for property additions related to the * * * vintage year and future years. The Commission permitted normalization treatment for the four percent investment tax credit. The additional six percent investment tax credit and the investment tax credit related to property depreciated under the Accelerated Cost Recovery System have been treated as ratable cost of service reductions for ratemaking purposes.

In * * * the Utilities placed in service one unit of Facility A. A second and third unit were placed in service in * * * and * * * respectively, Additions have been made to Facility A every year from * * *. Accelerated depreciation has been used for purposes of federal income tax and the Utilities have normalized the tax benefits. In * * * Utility B placed in service one unit of Facility B and claimed investment tax credits with respect to a portion of the Facility under section 48(d) of the Code.

In 1987, the Utilities sold their interests in Facility A to a group of investors and, as part of the same transaction, immediately leased back those interests. At the time of the sale the Utilities had unamortized accumulated deferred investment tax credits and unamortized deferred tax reserves resulting from accelerated depreciation relating to Facility A.

In 1987, Utility B sold its interest in Facility B to a different group of investors and, as part of the same transaction, leased back that interest. At the time of the sale Utility B had unamortized accumulated deferred investment tax credits relating to Facility B. Certain of those investors elected under section 48(d) of the Code to pass their share of the investment credit to Utility B.

ISSUE NUMBER ONE

Portions of Facility A were placed in service subsequent to the 1980 calendar year. The depreciation on such property is subject to the normalization requirements of section 168(f)(2) of the Code which provides that accelerated depreciation is unavailable for public utility property unless the taxpayer uses a normalization method of accounting. The balance of the property at Facility A was placed in service prior to 1980. The Commission has allowed normalization treatment for ratemaking purposes for the depreciation on such property. In Rev. Rul. 87-137, 1987-2 C.B. 64, the Internal Revenue Service held that such ratemaking treatment has the effect of an election under section 167(l)(4)(A) requiring normalization treatment with respect to such property.

A sale-leaseback transaction will result in the recognition of taxable income by the Utilities. All prior deferred taxes will be removed from the deferred tax reserve as set forth in section 1.167(l)-1(h)(2) of the Income Tax Regulations which provides for the reduction of the deferred tax reserve upon the retirement of assets or when federal income taxes payable are greater by reason of the prior use of accelerated depreciation. After application of this section, the deferred tax reserve resulting from accelerated depreciation ceases to exist for accounting purposes. From an economic standpoint, there are no longer any deferred taxes resulting from accelerated depreciation on the assets sold. The deferred gain or loss is the selling price reduced by net book cost and increased by any deferred tax reserve that may have existed prior to the sale. Neither sections 167(1) nor 168(f)(2) of the Code provide for restrictions on the regulatory treatment of the deferred gain/loss and the deferred income taxes on the sale, once the provisions of section 1.167(1)-1(h)(2) of the regulations have been satisfied.

Accordingly, we rule that there are no restrictions on the Commissions' regulatory treatment, or the Taxpayer's treatment in its regulated books of account, of the deferred gain or loss or of the deferred income taxes resulting from the sale-leaseback transaction, so long as all prior deferred tax reserves are removed pursuant to section 1.167(1)-1(h)(2) of the regulations.

ISSUE NUMBER TWO

Taxpayer has represented that it made a timely election to use the immediate flow-through of section 46(f)(3) of the Code for the investment tax credit with respect to certain property placed in service during the years 1975 through 1980. Section 46(f)(3) provides that if a taxpayer makes an election under that section then the limitations on accounting for the investment credit provided in sections 46(f)(1) and 46(f)(2) do not apply to the property of the taxpayer to which section 167(1)(2)(C) applies.

Based on the Taxpayer's representation that a timely election was made under section 46(f)(3) of the Code and based on the Taxpayer's implied representation that section 167(1)(2)(C) applies to the property in question, we rule that there are no ratemaking or accounting limitations under sections 46(f)(1) and 46(f)(2) with respect to the four percent portion of the unamortized investment credits relating to property placed in service during the years 1975 through 1980 that is part of the sale-leaseback transaction.

ISSUE NUMBER THREE

The unamortized investment credits on property placed in service at Facility A subsequent to 1980 and the six percent unamortized investment credit relating to property placed in service from 1975 through 1980 are treated identically for ratemaking purposes and on the taxpayer's regulated books of account. Accordingly, the treatment of these credits upon the sale-leaseback is the same.

Section 167(1)(3)(A) of the Code defines public utility property, in part, as property used predominantly in the trade or business of the furnishing or sale of electrical energy if the rates for such furnishing or sale have been established or approved by a State or political subdivision thereof, by any agency of the United States, or by a public service or public utility commission of a State or political subdivision thereof.

Section 1.168-3(c)(10)(ii) of the Proposed Income Tax Regulations provides that public utility property includes property leased to a person that uses such property in a public utility activity such as the trade or business of the furnishing or sale of electrical energy. Although this is a proposed regulation without the force and effect of final regulations, it is clear that Congress envisioned similar requirements for normalization under section 168 of the Code as were in effect under section 167. Therefore, it is appropriate to look to the regulations under section 167.

Section 1.167(1)-3(b) of the regulations provides that the definition of public utility property includes property leased by a taxpayer where the leasing of such property is part of the lessor's section 167(1) public utility activity or where the predominant use of such property by the lessee is in a section 167(1) activity. Although section 1.167(1)-3(b)(1) provides that the lessor in the sale-leaseback transaction is not subject to normalization if the lessor is not subject to the jurisdiction of a regulatory body described in section 167(1)(3)(A) of the Code, section 1.167(1)-3(b)(2) provides that the payments of rent by the lessee may be subject to a form of normalization.

Based on an analysis of the use of the property in question after the sale-leaseback transaction we rule that such property remains public utility property after the transaction.

Unlike the situation when public utility property is sold outright, in the sale-leaseback transaction the Utilities and their ratepayers continue to bear the cost of the property over the lease term. The regulated depreciation expense is simply replaced by a regulated rental expense. This is a critical factor in a determination of the proper treatment of the unamortized credits after the sale-leaseback transaction. Accordingly, in the context of the sale-leaseback transaction you have presented, we hold that the six percent portion of unamortized investment credits relating to property placed in service during the years 1975 through 1980 and the unamortized investment credits relating to property placed in service at Facility A during 1981 and subsequent years may be ratably amortized on a straight-line basis over a period no shorter than the lease term to reduce cost of service for ratemaking purposes and on its regulated books of account.

ISSUE NUMBER FOUR

Section 48(d)(1) of the Code provides that the lessor of new section 38 property may generally elect to treat the lessee of such property as having acquired such property for an amount equal to the fair market value of such property. Section 48(d)(3) provides further that if the lessor makes the election provided for in section 48(d)(1) then the lessee is treated as having acquired such property for purposes of subpart E, Part IV, Subchapter A of the Code which includes the normalization rules of section 46(f). Accordingly, the Taxpayer-Lessee is treated as the owner of the property that was part of the sale-leaseback transaction and can normalize the credits associated with the leased property. Furthermore, we rule that the credit available to the Taxpayer under section 48(d) may be ratably amortized on a straight-line basis over a period no shorter than the lease term to reduce cost of service for ratemaking purposes and on its regulated books of account.

This ruling is directed only to the taxpayer that requested it. Section 6110(j)(3) of the Internal Revenue Code provides that it may not be used or cited as precedent. Temporary or final regulations pertaining to one or more of the issues addressed in this ruling have not yet been adopted. Therefore, to the extent the regulations are inconsistent with any conclusions in the ruling, this ruling will be modified or revoked by adoption of temporary or final regulations. See section 16.04 of Rev. Proc. 89-1, 1989-1 I.R.B. 8, 19. However, when the criteria in section 16.05 of Rev. Proc. 89-1 are satisfied, a ruling is not revoked or modified retroactively, except in rare or unusual circumstances.

In accordance with your power of attorney, a copy of this letter is being sent to your authorized representative.

PECO STATEMENT NO. 10

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY

OF

J. GREGORY SIDAK

Regarding an Economic and Constitutional Analysis of the Justness and Reasonableness of PECO Energy's Full Recovery of It's Stranded Costs

TABLE OF CONTENTS

TESTIMONY OF J. GREGORY SIDAK

REGARDING AN ECONOMIC AND CONSTITUTIONAL ANALYSIS OF THE JUSTNESS AND REASONABLENESS OF PECO ENERGY'S FULL RECOVERY OF ITS STRANDED COSTS

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

A. J. Gregory Sidak, American Enterprise Institute for Public Policy Research, 1150 Seventeenth Street, N.W., Washington, D.C. 20036.

PURPOSE AND SCOPE OF TESTIMONY

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

A. I have been asked by PECO Energy to examine whether it would be just and reasonable under the Electricity Generation Customer Choice and Competition Act ("the Act") for the Commission to permit PECO Energy full recovery of its stranded costs pursuant to its restructuring. I use economic theory and the economic history of public utility regulation to give content to the legal requirements of the "just and reasonable" standard of sections 2804(13), 2804(14), and 2808 of the Act. My analysis draws from my article with Professor Daniel F. Spulber, "Deregulatory Takings and Breach of the Regulatory Contract," 71 *New York University Law Review* 851 (1996). I am testifying in my individual capacity, and not on behalf of the American Enterprise Institute or Yale School of Management.

CONCLUSION

Q. **What are your major conclusions?**

A. It would be "just and reasonable" under the Electricity Generation Customer Choice and Competition Act for the Commission to permit PECO Energy full recovery of its stranded costs pursuant to the Act. As sections 2803 and 2808(c) of the Act note, stranded costs are costs "which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market." Such stranded costs, the Act makes clear, include "regulatory assets and other deferred charges typically recoverable under current regulatory practice" and other generation-related costs.

My analysis of the economic objectives and historical origins of public utility regulation is focused on what it means for utilities and regulators mutually to have considered investments to be "traditionally recoverable under a regulated environment." First, I show that historical evidence substantiates the existence of a "regulatory contract" and that compelling economic arguments confirm the need for such a contract between the electric utility and the state. To phrase matters in terms of the Act, there is a powerful economic argument that a Pennsylvania utility expected, under traditional regulatory practice, to receive a reasonable opportunity to earn revenues sufficient to recover its prudently incurred investments and a competitive return on those investments. Pennsylvania would breach the regulatory contract if it were to order retail wheeling without allowing the incumbent utility (that is, PECO Energy) to achieve full recovery of the stranded costs of its prudently incurred investments. Second, I show that Pennsylvania's failure to allow PECO Energy that opportunity would also effect a taking of property under the Fifth Amendment of the U.S. Constitution.

I. The Regulatory Contract

A. Definitions

Q. **What is the "regulatory contract"?**

A. Investor-owned electric companies are public utilities that assumed obligations to serve in return for the regulator's assurance that those utilities would have the reasonable opportunity to earn a competitive return on invested capital, along with the compensation for the full cost of providing service. Regulators protect the utility's opportunity to earn a competitive return by controlling entry into its market; regulators also restrict the maximum earnings of the utility through rate setting, and they establish service requirements such as provider of last resort and other rules. That arrangement, known as the *regulatory contract*, enabled the regulators to reconcile their ceilings on the earnings of utilities with the requirement that, in terms of actuarially expected value, prospective investors be offered a competitive rate of return on their investments. The regulator was thus said to have entered into a bargain with the public utility: In return for assuming an obligation to serve and charging not more than "just and reasonable" prices on a nondiscriminatory basis, the utility received a franchise protected by entry regulation and the reasonable opportunity to earn income sufficient to recover, and to earn a competitive rate of return on, its invested capital.

Q. **Does the Electricity Generation Customer Choice and Competition Act reflect the existence of a regulatory contract in Pennsylvania?**

A. Yes. The Legislature's declaration of policy in section 2802 outlines the principles of the regulatory contract in Pennsylvania. Section 2802(13) notes that, until the 1997 Act, little competition existed under the Commission's regulation:

> Under current law and regulation there exists some competition in the *wholesale market for the generation of electricity; but the generation,* transmission, distribution and retail sale of electricity is provided generally by public utilities under bundled rates regulated by the Commission. The procedures established under this chapter provide for a fair and orderly transition from the current regulated structure to a structure under which retail customers will have direct access to a competitive market for the generation and sale or purchase of electricity.

Moreover, as the preceding passage indicates, electric utilities in Pennsylvania have been subject to "rates regulated by the Commission." Finally, the Legislature notes, in section 2802(15), that electric utilities in Pennsylvania undertook obligations to serve and detrimentally relied upon the preexisting regulatory framework:

> . . . heretofore, public utilities generally have had an obligation to serve customers within their defined service territories; consistent with that obligation, have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of *their customers; and have entered into long-term power supply*

agreements as required by federal law.

The Legislature also notes, in section 2802(17), that electric utilities in Pennsylvania pursued the Commonwealth's social objectives through the subsidies implicit in their structure of bundled rates:

> There are certain public purpose costs, including programs for low-income assistance, energy conservation and others, which have been implemented and supported by public utilities' bundled rates. The public purpose is to be promoted by continuing universal service and energy conservation policies, protections and services . . . .

As the second sentence in that paragraph indicates, the Legislature wants to continue to achieve those social objectives, even after the competitive restructuring of the electric power industry in the Commonwealth.

Q. **How do "incumbent burdens" affect the regulatory contract?**

A. When the state maintains regulatory obligations while it simultaneously eases entry restrictions, incumbent utilities encounter costly competitive disadvantages, known as "incumbent burdens." Regulators typically require the public utility to provide universal service at a fixed price, regardless of the true cost of service, and to act as the carrier of last resort. In addition, regulation denies the utility the pricing flexibility of the entrant, which places the utility at a competitive disadvantage. New entrants into regulated markets, of course, first target those customers whom regulators require the regulated incumbent to charge prices exceeding cost so that other customers may be charged prices below cost. When the state deregulates entry, it will jeopardize the incumbent utility's financial solvency unless the costs of incumbent burdens are either shared by all firms in the market or explicitly reimbursed by some third party. It is easy to cheer the arrival of competition to industries where it previously has been regulated or forbidden by law. But the predictable appeal that competition holds for legislators and regulators should not obscure the fact that the transition from regulated monopoly to competition is not free. Unless accompanied by other reforms, the advent of retail wheeling will preclude the recovery, through market-determined prices, of two sets of costs: the historical costs that the electric utility incurred to discharge its obligation to serve, and the future costs that incumbent burdens continue to impose on that incumbent utility.

Q. **Does the Electricity Generation Customer Choice and Competition Act recognize the existence of incumbent burdens in Pennsylvania?**

A. Yes. The passages quoted above from sections 2802(15) and 2802(17) are explicit recognition by the Legislature of the incumbent burdens that electric utilities have borne in Pennsylvania. Indeed, the Act not only recognizes the existence of incumbent burdens borne by Pennsylvania utilities, but also continues and expands those burdens by, for example, expanding the obligation to serve and making it truly universal.

Q. **What are stranded costs?**

A. Stranded costs are costs that a utility is currently permitted to recover through its rates but whose recovery will be impeded or prevented by the advent of competition. Costs that might get stranded include assets used for electricity generation, power and fuel purchasing expenditures required under long-term contracts, "regulatory assets" consisting of expenses whose recovery has been deferred to keep rates temporarily from rising, and outlays required of the utilities by regulators to meet social goals such as subsidizing low-income users. Such costs are expenditures, approved or mandated by regulators, that the utility incurred in meeting its obligations to serve all customers in its service territory.

Q. **Does the Electricity Generation Customer Choice and Competition Act recognize the existence of stranded costs in Pennsylvania?**

A. Yes. The concept of stranded costs is an essential element of the Act. It is defined at length in section 2803 of the Act. The brief economic definition that I have provided above is consistent with the Legislature's understandably detailed definition and captures the essence of the Legislature's expression in section 2803 that stranded costs are costs "which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the Commission determines will remain following mitigation by the electric utility." Indeed, section 2808 of the Act sets forth a mechanism whereby incumbent utilities are to be provided an opportunity to "recover [their] transition or stranded costs."

B. Historical Origins of the Regulatory Contract

Q. **What is the historical basis for the regulatory contract?**

A. Municipalities and public utilities routinely entered into explicit contracts in the nineteenth century and early twentieth century, long before the advent of the state public utilities commissions. During the first half of the nineteenth century, city governments lacked the necessary financial resources and expertise to provide their citizens all the benefits that might flow from the momentous scientific and industrial developments of that era. So the cities solicited the help of private entrepreneurs.[1] State

[1]*See* WILLIAM M. IVINS & HERBERT DELAVAN MASON, THE CONTROL OF PUBLIC UTILITIES 4–15 (Baker, Voorhis & Co. 1908); 1 DELOS F. WILCOX, MUNICIPAL FRANCHISES 1–3 (Gervaise Press 1910); JOSEPH A. JOYCE, A TREATISE ON FRANCHISES 542–54 (Banks Law Publishing Co. 1914); HERBERT B. DORAU, MATERIALS FOR THE STUDY OF PUBLIC UTILITY

legislatures or local municipalities offered charters or franchises to utilities that gave the private firm access to public rights-of-way and often delegated to them the power of eminent domain. In return, the firm committed to build the costly infrastructures and accepted the obligation to serve the public on a nondiscriminatory basis at reasonable rates sufficient to recover the firm's investment. Each franchise was a bargained-for exchange.

Professor George Priest of Yale Law School notes that "[p]ublic utility companies voluntarily entered contracts subjecting themselves to regulation in order to gain authority to use public rights-of-way" and that "[r]egulation of the utility's activities and terms of business resulted from a negotiation between the municipal government and the utility in a context that both parties recognized saved the utility the costs of negotiating with and securing rights from the individual property owners they intended to serve." George L. Priest, *The Origins of Utility Regulation and the "Theories of Regulation" Debate,* 36 J.L. & ECON. 289, 303 (1992). Utility franchises evolved over time, ultimately creating administrative boards. *Id.* at 321. From those administrative boards grew the state regulatory commissions, most of which came into existence between 1907 and 1922. *Id.* at 296.

Q. **Do court decisions provide historical evidence of the existence of the regulatory contract?**

A. Yes. Numerous Supreme Court decisions confirm the understanding that the public utility entered into a contract with the state or municipal government. For example, in *The Binghamton Bridge*, 70 U.S. (3 Wall.) 51, 73 (1865), the Supreme Court stated:

ECONOMICS 2–9, 12–22, 33–61 (MacMillan Co. 1930); ELI WINSTON CLEMENS, ECONOMICS AND PUBLIC UTILITIES 72–73 (Appleton-Century-Crofts, Inc. 1950).

> The legislature . . . says to public-spirited citizens: "If you will embark, with your time, money, and skill, in an enterprise which will accommodate the public necessities, we will grant to you, for a limited period, or in perpetuity, privileges that will justify the expenditure of your money, and the employment of your time and skill." Such a grant is a contract, with mutual considerations, and justice and good policy alike require that the protection of the law should be assured to it.

Similarly, in *New Orleans Water-Works Co.* v. *Rivers*, 115 U.S. 674, 681 (1885), the Court said a utility's franchise to operate a waterworks

> was a contract, the obligation of which cannot be impaired by subsequent legislation, or by a change in her organic law. It is as much a contract, within the meaning of the Constitution of the United States, as a grant to a private corporation for a valuable consideration, or in consideration of public services to be rendered by it, of the exclusive right to construct and maintain a railroad within certain lines and between given points, or a bridge over a navigable stream within a prescribed distance above and below a designated point.

Accord, *New Orleans Gas Co.* v. *Louisiana Light Co.*, 115 U.S. 650, 661 (1885). In *Walla Walla City* v. *Walla Walla Water Co.*, 172 U.S. 1, 8–9 (1898), the Court stated:

> [T]his court has too often decided for the rule to be now questioned, that the grant of a right to supply gas or water to a municipality and its inhabitants through pipes and mains laid in the streets, upon condition

> of the performance of its service by the grantee, is the grant of a franchise vested in the State, in consideration of the performance of a public service, and after performance by the grantee, is a contract protected by the Constitution of the United States against state legislation to impair it.

The Supreme Court well recognized by the turn of the century that key provisions in the regulatory contract existed to ensure cost recovery for specialized investments and to deter opportunism. In 1898 it observed: "It is not to be supposed that the company would have entered upon this large undertaking in view of the possibility that, in one of the sudden changes of public opinion to which all municipalities are more or less subject, the city might . . . practically extinguish the rights it had already granted to the company." *Walla Walla*, 172 U.S. at 17–18. In 1902, the Court similarly observed: "It would hardly be credible that capitalists about to invest money in what was then a somewhat uncertain venture, . . . would at the same time . . . . give the right to the [municipality] to change at its pleasure from time to time those important and fundamental rights affecting the very existence and financial success of the company . . . ." *Detroit* v. *Detroit Citizens' Street Railway Co.*, 184 U.S. 368, 385 (1902).

C. The Economic Rationale for the Regulatory Contract

Q. **Does economic theory support the existence of the regulatory contract?**

A. Yes. Economic analysis reinforces the conclusion drawn from historical analysis that the regulatory contract was necessary to address cost recovery, asset specificity, opportunism, and credible commitments. Consumers and businesses voluntarily participate in a market transaction only if they receive *gains from trade*—only if the transaction yields positive net benefits for them. A supplier will not invest in a transaction unless the supplier expects the returns from the transaction to cover all economic costs, including a competitive return to invested capital. That principle is summarized in Professor Armen Alchian's classic definition of cost: "In economics, the cost of an event is the highest-valued opportunity necessarily forsaken." Armen A. Alchian, *Cost*, *in* 3 INTERNATIONAL ENCYCLOPEDIA OF THE SOCIAL SCIENCES 404, 404 (David L. Sills ed., MacMillan Co. & Free Press 1968). The supplier's costs of investing in the transaction include the highest net benefit of all opportunities forgone, known as *opportunity cost*.

Q. **What is the significance of transaction-specific investment to the regulatory contract?**

A. The investments of an electric utility are highly specialized. They are specifically designed to enable the utility to perform its obligations under the regulatory contract. That capital investment cannot be picked up and moved if the transaction between the utility and the state ends prematurely. Such investment is called "transaction specific." Utilities would not have undertaken the extensive investments required to provide regulated service within their franchise region without the opportunity to recover their costs. As the President's Council of Economic Advisers noted in 1996:

> [T]here is an important difference between regulated and unregulated markets. Unregulated firms bear the risk of stranded costs but are entitled to high profits if things go unexpectedly well. In contrast, utilities have been limited to regulated rates, intended to yield no more than a fair return on their investments. If competition were unexpectedly allowed, utilities would be exposed to low returns without having had the chance to reap the full expected returns in good

> times, *thus denying them the return promised to induce the initial investment.* A strong case therefore can be made for allowing utilities to recover stranded costs . . . .

1996 ECONOMIC REPORT OF THE PRESIDENT 817 (emphasis added). Professor Daniel Spulber of Northwestern University has made a similar point: "The regulatory contract is often justified as a means of mitigating the risks of making large irreversible investments that are faced by regulated utilities." DANIEL F. SPULBER, REGULATION AND MARKETS 610 (MIT Press 1989). "Customers of utilities gain from such commitments, since efficient levels of investment yield lower costs of service. There is an incentive to honor commitments regarding compensatory rates of return to assure that regulated firms will undertake future investment and that they will maintain their existing capital equipment." *Id. See also* Glenn Blackmon & Richard Zeckhauser, *Fragile Commitments and the Regulatory Process*, 9 YALE J. ON REG. 73, 76–78 (1992).

Cost-of-service regulation of public utilities is based on allowing a utility the opportunity to recover its investment, including a competitive rate of return. "In the absence of a detailed long-term contract," note Professors Laffont and Tirole, "the regulated firm may refrain from investing in the fear that once the investment is in place, the regulator would pay only for variable cost and would not allow the firm to recoup its sunk cost." JEAN-JACQUES LAFFONT & JEAN TIROLE, A THEORY OF INCENTIVES IN PROCUREMENT AND REGULATION 54 (MIT Press 1993). Utilities have had to undertake substantial investments to discharge their obligation to serve. Indeed, as discussed previously, section 2802(15) of the Act itself confirms this fact, as it recognizes both that Pennsylvania "public utilities generally have had an obligation to serve customers within their defined service territories," and that, "*consistent with that obligation,*" utilities "have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers." (emphasis added). The purpose of a regulatory contract is to provide for recovery of "economic costs," by which I mean the full cost of an activity, including direct expenditures, the time cost of money expended for capital investment, and any other opportunity costs.

The expectation that a utility will be able to recover its costs applies as well to new expenditures that the utility makes to satisfy regulatory obligations even if the industry is partially or fully deregulated. The utility cannot be asked to provide services in the competitive market at regulated prices that do not allow for full cost recovery, particularly when the firm is mandated to offer unbundled services. Moreover, the introduction of retail wheeling does not eliminate the responsibilities of regulatory authorities to allow the incumbent utility a reasonable opportunity to recover fully those costs *already incurred* to satisfy the utility's obligation to serve. Regulators have a continuing responsibility to allow the utility the opportunity to recover those costs.

Q. **What is the significance of regulatory opportunism and asset specificity to the regulatory contract?**

A. The noted economist Oliver Williamson defines *opportunism* as "self-interest seeking with guile." OLIVER E. WILLIAMSON, THE ECONOMIC INSTITUTIONS OF CAPITALISM: FIRMS, MARKETS, RELATIONAL CONTRACTING 47 (Free Press 1985). He describes utility regulation as a "highly incomplete form of long-term contracting" in which the terms are adapted to "changing circumstances" to assure the supplier of a fair rate of return. Oliver E. Williamson, *Franchise Bidding for Natural Monopolies—in General and with Respect to CATV*, 7 BELL J. ECON. 73, 91 (1976). The problem of regulatory opportunism stems from the fact that stranded investments and regulatory assets, including expenditures for plant and equipment and capitalized expenditures to perform duties mandated by regulators, are likely to be transaction-specific. That is, the assets have little value outside the regulatory transaction. The regulatory contract that was suited for an industry with significant asset specificity is not suited for an industry in which asset specificity has declined considerably.

This problem of incompatibility between the degree of asset specificity and the regulatory regime arises in the transition to competition: Incumbent utilities have not yet recovered the costs of their assets that are specific to a regulated market, and entrants meanwhile can invest in facilities that have considerably less asset specificity or can provide service with minimal investment. Of course, as noted previously, the Act also recognizes this fact through, for example, its definition of stranded costs in section 2803 as generation-related costs "which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market." It would breach the regulatory contract for the regulator to make unilateral changes in regulation that might prevent a utility from recovering the economic costs of investments that it made to discharge its regulatory obligations to serve. Contractual protections of the interests of the utility and its investors exist so that the state and private companies can continue to make agreements requiring investments in highly specialized capital. The regulatory contract depends on protections to reduce and allocate the risk of cost recovery for specialized assets that cannot be salvaged if the contract is not performed.

Q. **What is the significance of regulatory "hold-up" to the regulatory contract?**

A. As with private contracts, the regulatory contract is designed to address "hold-up" problems. By incurring substantial capital expenditures to perform its obligation to serve, the utility is vulnerable to confiscation. In the absence of contract enforcement, the utility is at the mercy of the regulatory authority: By lowering rates to levels that do not allow a full recovery of costs, after the facilities have been created, a regulator could take advantage of the utility and its investors. The prices posted by a utility can be raised or lowered without incurring more than the costs of communicating the new tariffs to customers. The regulated rates are thus much more flexible than are the utility's capital facilities because the latter are irreversible, market-specific investments. To the extent that they were tailored to meet regulatory obligations to serve, the utility's investments may not be fully recovered in a competitive market setting. Once again, to use the Act's formulation, investments which "traditionally would be recoverable under a regulated environment . . . may not be recoverable in a competitive electric generation market." That means that the regulatory contract is necessary as a means of protecting the regulated utility from regulatory "hold-up."

Q. **How does regulatory opportunism affect the utility's "core" customers?**

A. "Core" customers are those customers of the incumbent utility who have limited opportunities to switch to competitive suppliers, while "noncore" customers are better able to seek alternatives. Typically, core customers are residential and small business customers, while noncore customers are large commercial and industrial customers. Noncore customers can rely on the incumbent utility as a backup service or carrier of last resort. Core customers thus often bear a greater share of overhead costs when deregulation leads to selective entry and bypass of the incumbent utility. With continued regulation of the utility's core markets, some of those costs would be shifted to remaining core customers while others would represent losses for utility investors. Thus, some putative benefits of competition are merely an income transfer from the utility's investors and core customers to its noncore customers, rather than a gain due entirely to enhanced productivity. Deregulation should not, however, be used as a means to achieve gains for some customers by imposing losses on the utility's investors.

The Competition Act's prohibitions against cost shifting in the design of the Competitive Transition Charge temper this, but adverse affects may still be felt by core customers.

Q. **What is the significance of credible commitments to the regulatory contract?**

A. *Commitments made in bargaining situations influence the behavior of other actors only* to the extent that the person making such commitments is credibly bound (by himself or others) to honoring them. The notion of enforceable agreements plays a similar role in regulated industries as it does in competitive markets. The level of investment in long-lived infrastructure undertaken by a regulated (or recently privatized) public utility depends critically on regulatory institutions having been designed to ensure the credibility of the regulator's commitments that it will not act opportunistically once the utility has placed those nonsalvageable assets into service. The President's Council of Economic Advisers has similarly noted:

> [R]ecovery should be allowed for legitimate stranded costs. The equity reason for doing so is clear, but there is also a strong efficiency reason for honoring regulators' promises. Credible government is key to a successful market economy, because it is so important for encouraging long-term investments. Although policy reforms inevitably impose losses on some holders of existing assets, good policy tries to mitigate such losses for investments made based on earlier rules . . . .

1996 ECONOMIC REPORT OF THE PRESIDENT 817. The utility's investors would not be *willing to commit vast amounts of capital to carry out an obligation to serve unless the* regulator's offer of an opportunity to earn a fair rate of return were credible. Regulated utilities relied upon those contractual assurances in planning and carrying out their investment and service plans. Conversely, the regulator would not be willing to provide a franchise protected by entry regulation and to authorize the utility's pricing and investment plans unless the utility's promises to provide services were credible. The legal and public policy context in which the regulatory process operates provides guarantees to the parties to the regulatory contract.

As with private contracts, the regulatory contract must involve consideration, for the agreement is voluntary. The first public utilities did not spring into existence as the result of some government conscription of private capital. The regulated utility submits to various regulatory restrictions including price regulations, quality-of-service requirements, and common carrier regulations. In return, the regulated firm receives a franchise subject to entry regulation in its service territory, and its investors are allowed a reasonable opportunity to earn revenues subject to a rate-of-return constraint. Without the expectation of earning a competitive rate of return, investors would not be willing to commit funds for the establishment and operation of the utility. The funds are committed to provide services to the customers of the regulated utility. Once the utility invests those funds, the long depreciation schedules typical in electricity regulation credibly commit the utility to performing its obligations under the regulatory contract by denying it the opportunity to recover its capital before the end of its useful life.

Q. **What is the significance of relational contracting to the regulatory contract?**

A. A question sometimes asked in regulatory proceedings is, "Where, Professor *X*, is this regulatory contract to which your testimony refers?" The regulatory contract is recorded in a bundle of documents not necessarily limited to a single franchise agreement: public utility statutes, utility commission precedents, adjudicatory decisions, rulemakings, hearings on the record, formal notices of proposed rulemaking, and public commentary. Such reasoning is not novel, for it is the same logic that the Supreme Court has applied in analyzing whether state legislation has given rise to a contractual obligation:

> In general, a statute is itself treated as a contract when the language and circumstances evince a legislative intent to create private rights of a contractual nature enforceable against the State. In addition, statutes governing the interpretation and enforcement of contracts may be regarded as forming part of the obligation of contracts made under their aegis.

United States Trust Co. v. *New Jersey*, 431 U.S. 1, 17 n.14 (1977). Although the original franchise agreement between the public utility and a municipality is usually the critical first document in the bundle of agreements concerning the relationship between the state and the utility, no single document is likely to encapsulate the entire regulatory contract. The relational contract between the utility and the regulated firm is analogous to a corporation, which is an easily identified entity but consists of multiple contracts that define the firm.

Professor Victor Goldberg of Columbia Law School has observed that private contracts involve both an *ongoing relationship* that uses "rough formulae or mutual agreement to adjust the contract to current situations," and *agency*, which occurs when a firm deals with many customers who "find it desirable to act collectively through an agent both to negotiate the terms and to administer the contract over time." Victor P. Goldberg, *Regulation and Administered Contracts*, 7 BELL J. ECON. 426, 428, 429 (1976). Goldberg asserts that "[r]egulation can be viewed as an implicit administered contract in which both elements are significant." *Id.* at 427.

Even if there were no explicit documentation at all of the relationship between the regulator and the firm, the regulatory contract would still represent an unambiguous meeting of the minds. As with private contracts, the regulatory contract has both express and implied provisions. The franchise award, orders approving rates, and orders approving capital expenditures are clearly formal written agreements. Inclusion of capital expenditures in the regulated rate base is certainly a formal contractual agreement. The regulatory contract also has implied features. The utility undertakes capital expenditures of some extended economic lifetime in anticipation of cost recovery. Regulatory approval of such capital expenditures implies that there will not be fundamental changes in the regulator's approach to the company's market environment during the economic lifetime of those investments without addressing the issue of compensating investors.

Through the regulatory process, parties present testimony and evidence in formal public proceedings for the record. The agency gives formal notice of proposed rulemakings and considers the comments of interested parties. That process establishes the regulatory bargain and serves not only to make the process transparent, but also to assure the participants that their interests are protected, just as contract rights and remedies protect the parties to private contracts. The formal proceedings make a public record that helps to protect the legal and economic interests of consumers and the firm's investors.

Q. **What economic inefficiencies can result from denying utilities the full recovery of their stranded costs?**

A. Denying utilities the reasonable opportunity to recover stranded costs can raise utilities' cost of capital and discourage future investment in the industry. That result reflects the fact that the allocation of risk between a utility's investors and customers differs from its allocation in unregulated industries. Unregulated markets impose on investors the full costs of investments that turn out badly but let them keep all the profits of ventures that turn out well. Under traditional utility regulation, however, investors have neither borne much of the former risk nor enjoyed much of the latter benefits. Instead, regulators only allowed utilities to earn a fair rate of return based on just and reasonable prices.

Some argue that just as suppliers under competition have no entitlement to recover their sunk costs, so utilities have no such entitlement either. Consequently, the argument continues, if competition makes it impossible for a utility to recover those costs from its customers, then it should write off the costs. The argument ignores that, under both the competitive and regulated arrangements, the allocation of risk has been symmetrical—with large risks of loss in unregulated industries balanced by large opportunities for gain and, in the utility industries, shareholders sheltered from the risk of large losses and correspondingly denied the opportunity for big gains. A failure now by policy makers to permit a reasonable opportunity for full recovery of costs imposed under regulation in any transition to competition would leave investors with much of their equity expropriated by the change in the rules of the game.

It is true that it will be too late for current investors in utilities to do anything in response to a prohibition of recoupment. But investors can learn the lesson and conclude that investment in electric utilities is to be avoided assiduously in the future. More important, other prospective investors, seeing the contract abrogated, are certain to conclude that it may well be abrogated again whenever it is convenient for the regulator, and they, too, may take their resources elsewhere in the economy. Investors would demand a significant risk premium to provide incumbent utilities with the capital that they will need in the future to maintain and improve the transmission and distribution facilities that will be required to serve both themselves and their new competitors in electricity generation. The resulting shortage of capital for the electric power industry, and the consequent impediments to maintenance, modernization, and needed expansion, can hardly benefit the long-run interests of consumers or contribute to the efficiency and competitiveness of the economy.

In short, there are compelling efficiency reasons to give utilities the reasonable opportunity to achieve full recoupment of stranded costs in the course of the transition to competition. Even opponents of stranded cost recovery benefit from the regulator's continued fidelity to the regulatory contract. Regulators should permit rival firms to succeed only on the basis on relative efficiency. If regulators do so, the marketplace for electricity will be both competitive and efficient.

D. The Principal Components of the Regulatory Contract

Q. **What are the essential elements of the regulatory contract?**

A. The three components of the regulatory contract are entry controls, rate regulation, and utility service obligations. The state commission controls the entry of the utility's competitors and authorizes rates that give the utility's investors the opportunity to earn a "fair" rate of return on their investment. In return, the regulated utility must comply with regulatory accounting procedures for the disclosure of its costs, abide by price regulations, limit its business activities in other markets, invest in sufficient generation, transmission, and distribution services to all customers within its service territory who request service, operate efficiently as determined by the regulatory commission, make only investments that are "prudent," meet regulatory standards for quality of service, and comply with a host of other provisions. For example, as recently as February of 1997, the Supreme Court described the origin of the regulatory contract in the gas industry in these terms: "It seemed virtually an economic necessity for States to provide a single, local franchise with a business opportunity free of competition from any source, within or without the State, so long as the creation of exclusive franchises under state law could be balanced by regulation and the imposition of obligations to the consuming public upon the franchised retailers." *General Motors Corp.* v. *Tracy*, 117 S. Ct. 811 (1997). The Court noted that there occurred "essentially the same evolution in the electric industry." *Id.*

Significantly, as I have discussed earlier, the Act recognizes the existence of all three of those components in Pennsylvania. Thus, while section 2802(13) of the Act notes that "[u]nder current law and regulation there exists some competition in the wholesale market for the generation of electricity," it also recognizes that the situation is very different with respect to the retail electricity market. With respect to retail markets, the Act notes both the absence of competition and the existence of rate regulation:

> [T]he generation, transmission, distribution, and retail sale of electricity is provided generally by public utilities under bundled rates regulated by the Commission. The procedures established under this chapter provide for a fair and orderly transition from the current regulated structure to a structure under which retail customers will have direct access to a competitive market for the generation and sale or purchase of electricity.

Id. Finally, section 2802(15) of the Act confirms the existence of utility service obligations, and that, "consistent with [those] obligation[s], [Pennsylvania utilities] have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers." Those service obligations, which began during the period of municipal contracting with utilities and which were greatly expanded by the Pennsylvania public utility code, were in some ways expanded even further by the Act.

The broad terms of the regulatory contract are found in the regulatory authority's preceding decisions, legislation, and judicial oversight. Regulated rates are set through public rate hearings that follow rules of administrative procedure. The regulatory authority approves the utility's investment projects through prudency reviews and used-and-useful hearings. The regulators approve the prices charged by the regulated utility and review its financial performance. Thus, the regulatory contract is between the utility and the regulatory commission, as the agent of the legislature, which in turn represents the general public.

Q. **Does the regulatory contract regulate entry?**

A. Yes. Laws and regulations limiting the entry of competitors into the service territory of the incumbent utility are a standard feature of the regulatory contract. Regulatory commissions control entry through the awarding of franchises and the requirement of a certificate of public convenience and necessity. Entry controls have traditionally limited competition for utilities and allowed them the opportunity to earn a fair rate of return on their investments while conforming to rate regulation and regulatory service obligations. The easing of regulatory entry barriers to achieve the benefits of competition represents a fundamental change in the terms of the regulatory contract. To avoid confiscatory outcomes, those changes need to be counterbalanced by altering both the responsibilities and compensation for incumbent utilities.

The traditional justification for entry restrictions in the electric power industry has been to achieve the cost gains from *natural monopoly*. A technology exhibits the property of natural monopoly if one firm can produce the product or service at lower cost than can two or more firms. Competition brings cost efficiencies and incentives for innovation that cannot be achieved through entry and rate regulation. Moreover, the high transaction costs associated with cost-of-service regulation lead many to question whether any potential cost gains can possibly justify continuing to regulate entry.

Given these concerns and questions, state PUCs are tempted to repudiate entry regulation in the electric power industry. The elimination of franchise protection by the state legislature or PUC, however, is a unilateral change of a fundamental term in the regulatory contract. Although cost efficiencies may no longer justify continuing entry regulations, that changed circumstance does not eliminate the regulator's responsibility to allow incumbent utilities to recover their costs incurred before the change in the regulatory contract.

Q. **Does the regulatory contract grant the incumbent utility a statutory monopoly?**

A. No. A common misunderstanding of the regulatory contract is that an essential component of that agreement is the government's grant of a monopoly to the investor-owned utility. The grant may take the form of an exclusive franchise or a statutory prohibition on competitive entry. To the contrary, the regulatory contract does *not* require monopoly, and the misapprehension that it does, in turn, supplies the erroneous premise for two misplaced arguments. The first is the assertion that those who defend the regulatory contract are necessarily opposed to competition and unconditionally maintain that, by itself, the government's introduction of competition into the market in question would constitute breach of the regulatory contract. The second misplaced argument is the assertion that one can disprove the existence of the regulatory contract in a given state by pointing to the existence there of a statute or state constitutional provision that forbids the state or any of its municipalities from granting an exclusive franchise. Neither of those two arguments is correct.

Suppose that a state not only forbade exclusive franchises, but also failed to create—by statute, common law, or regulatory practice of long standing—any alternative cost recovery mechanism that credibly assured the utility that the regulator would provide the utility the opportunity to recover its irreversible, nonsalvageable investments. In that institutional setting, a private company would be reluctant to contract for the long-term supply of any amount of electricity that would necessitate any incremental investment in nonsalvageable assets; and even if the company *were* willing enter into such a contract, investors would be unwilling to supply the company with the requisite capital unless they were paid a risk premium substantial enough to compensate for the risk that the capital used to make those investments in nonsalvageable assets might never be recovered and a competitive return on that capital might never be received. That sort of risk premium is what investors routinely demand from irreversible investments in third-world countries that suffer from political instability and correspondingly unreliable judicial and regulatory institutions for the protection of private property. Most important, consumers suffer under such circumstances because it is they who ultimately pay the risk premium that is necessary to attract the investment required for the utility to render service, and it is they who will bear the disruption in service if regulatory instability induces the public utility to disinvest.

It should therefore be evident where the fallacy lies in the second argument—that is, the argument that the existence of a statute or state constitutional provision that *forbids the state or any of its municipalities from granting* an exclusive franchise disproves the existence of the regulatory contract in that state. It is a factual matter beyond any dispute that some states forbid the grant of an exclusive franchise. The existence of such a prohibition, however, is hardly evidence that the regulatory contract does not exist in that state. All that such a fact proves is that the state has chosen a different means by which to achieve the ends for which franchise exclusivity is the chosen means in other states. The common objective in the two cases is to create the opportunity for recovery by the utility of the prudently incurred costs of irreversible, nonsalvageable investments that it made to discharge its obligation to serve customers within its service area. For example, a state, while not granting exclusivity to the incumbent utility, may nonetheless refrain from taking actions that would threaten the firm's recovery of nonsalvageable investments. That limitation on the discretion of the licensing authority may include the statutory directive to the public utilities commission not to grant an overlapping certificate of public necessity without good cause.

It should now be evident as well where the fallacy lies in the first misplaced argument—that is, the argument that those who defend the regulatory contract necessarily oppose competition and maintain that, by itself, the government's introduction of competition into the regulated market would breach the regulatory contract. Entry regulation is simply a means to an end; it is not the end in itself. The appropriate objective—the objective that advances economic efficiency and consumer welfare—is for the regulator to provide a credible mechanism by which the utility will have the opportunity to recover the costs of (and a competitive return *on*) its irreversible, nonsalvageable investments over the course of their useful lives. If a state in the past has chosen franchise exclusivity as the mechanism to achieve that objective but now wants to reverse course and allow open entry, then it must simultaneously introduce an alternative policy that is equally efficacious in creating the opportunity for achieving that cost recovery objective. In short, a breach of the regulatory contract does *not* necessarily occur when the state abolishes entry regulation; but a breach *does* necessarily occur when the state abolishes entry regulation without simultaneously imposing an alternative policy that will achieve the same cost-recovery objective for which entry regulation was originally intended.

Q. **Does the regulatory contract regulate the utility's rates?**

A. Yes. Rate regulation by state PUCs is another standard feature of the regulatory contract. Rate regulation to control monopoly power generally accompanies entry restrictions that were put in place to protect natural monopoly. In addition to controlling monopoly power, rate regulation often is perceived as a means of achieving universal service and maintaining reasonable rates for consumers and industry.

The power to exercise control over rates also places responsibilities on regulators. The regulatory commission cannot unilaterally terminate its obligation to the utility. The utility's need to raise capital repeatedly, and constitutional protections against takings under the Fifth and Fourteenth Amendments, require regulators to take into account the interests of investors. Moreover, the decision to move to a competitive or "deregulated" environment does not absolve the regulators of their responsibility under the regulatory contract to permit incumbent utilities to earn competitive rates of return on their investments. Competition can be expected to lead directly to falling revenues for the incumbent utility, significantly impairing or preventing its ability to earn competitive rates of return on their investments. Regulators will exacerbate that shortfall if they continue to impose, or expand, performance requirements on the incumbent utilities. In addition, section 2804(4) of the Act imposes rate caps on utilities, thus Section 2808 prohibits the competitive transition charge being charged in a manner that shifts inter-class or intra-class costs. Thus making it effectively impossible for incumbent utilities to "rebalance" their rates to ameliorate the revenue shortfall that follows abrogation of the former regulatory bargain (even assuming that rates could be raised in the new competitive market).

Q. **Does the regulatory contract impose on the utility an obligation to serve?**

A. Yes. As a general rule in antitrust law and in markets generally, a firm may unilaterally refuse to deal with any prospective customer. That rule does not apply to public utilities, however. Utilities carry an obligation to serve customers in their franchise region at posted prices. That obligation requires the utility to expand its generation, transmission, and distribution capacity to meet the growth and location of customer demand and to provide reliable service. Indeed, as noted earlier, the Act actually continues and expands the service obligations of incumbent utilities like PECO Energy.

The costs of the utility's capacity investments that were made to satisfy the obligations discussed above are recovered through their inclusion in the rate base. The utility earns the allowed rate of return on its capital expenditures net of depreciation. The utility recovers the cost of assets through depreciation allowances that are treated as operating costs. In short, the regulatory contract requires performance from the utility that has necessitated substantial capital expenditures, which were made subject to regulatory approval and oversight. If the regulator unilaterally changes the regulatory contract, a complete review of the utility's performance obligations becomes necessary.

Q. **Why is it necessary to obligate a utility to extend its network?**

A. For a fixed, geographically averaged price, the utility would stop expanding its network when the private marginal cost of doing so began to exceed the private marginal benefit. Regulators would prefer to have the network expanded to the point where *social* marginal cost equals *social* marginal benefit. Alternatively, the utility would depart from pricing its services at a fixed price and, instead, charge higher prices to customers in high-cost areas. Thus, the need to impose on the utility an obligation to extend its network is the direct implication of policies of universal service and rate averaging. For example, in *New York* ex rel. *New York & Queens Gas Co.* v. *McCall*, 245 U.S. 345, 351 (1917), the Supreme Court said:

> Corporations which devote their property to a public use may not pick and choose, *serving only the portions of the territory covered by their* franchises which it is presently profitable for them to serve and restricting the development of the remaining portions by leaving their inhabitants in discomfort without the service which they alone can render. To correct this disposition to serve where it is profitable and to neglect where it is not, is one of the important purposes for which these administrative commissions, with large powers, were called into existence . . . .

If a public utility having a uniform rate structure and a franchise protected by entry regulation is meeting or exceeding its revenue requirement, then it cannot refuse a request to extend its network to serve a new customer below incremental cost.

Q. **How does the regulatory contract regulate service quality?**

A. Regulators require a public utility to maintain specified levels of service quality. Quality of service is a fundamental part of the universal service requirement. Regulated utilities must maintain sufficient capacity not only to provide service to all customers who request it, but also to meet the peak demands of its customers. With variability of demand, the firm needs to carry the cost of substantial capital investment that can remain idle off peak. The effect of service quality regulation is that the type of capital equipment that the utility employs to meet its service obligations is tailored to satisfying regulatory specifications, which are often articulated in terms of engineering standards for reliability, capacity, and so on. Moreover, capacity investments are designed to meet service requirements while passing the test of prudency reviews and used-and-useful tests for cost recovery.

Service quality regulations have several significant implications for the recovery of stranded investment. First, it is often the case that the types of facilities that are needed to meet regulatory requirements are ill-suited to competitive markets. That fact does not in itself indicate that the regulated firm failed to invest wisely or that it embraced obsolete technology. Rather, the capacity that is best adapted for one type of market structure should not be expected to fit another type of market structure. For example, after airline deregulation, as airlines switched from direct routes to a hub-and-spoke system, they needed different airport accommodations and different types of planes. The capital equipment that a regulated monopoly needs to provide service is unlikely to match the needs of a competitive firm.

Second, the capital equipment needed by competitive firms is meant to satisfy customer needs rather than one-size-fits-all technological standards. Thus, compared with a firm whose capital investment is designed to serve all in a uniform manner, entrants can target service offerings to specific customer needs and provide better service to some classes of customers.

Third, because the incumbent regulated firm built a system with substantial excess capacity, its cost of maintenance and operation can be expected to differ from those of entrants, who have the prerogative to ration customers. Moreover, the capital facilities of incumbents are long-lived, so that entrants can take advantage of technological change in the design of their facilities. Technological obsolescence of incumbent facilities thus need not indicate errors in the incumbent's investment strategy.

In the case of electric power, the utility must maintain sufficient generation, transmission, and distribution capacity to meet the pattern of demand with baseload, shoulder, and peaking capacity. Because the cost of storing power is prohibitive, and because regulators do not permit rationing of residential and commercial customers, the utility must recover the costs of capacity through demand charges based on maximum use, and through energy charges. Moreover, the utility provides standby capacity because it must remain prepared to serve customers that self-generate or purchase power elsewhere, whenever they have additional needs for power.

Regulatory standards for generation, transmission, and distribution capacity generally specify high levels of reliability. Utilities attempt to meet their power demand at lowest reasonable cost by operating an assortment of power plants (including nuclear, gas, fuel oil, and coal) and by purchasing power. Their supply problem differs from that of specialized entrants who can simply contribute power for resale within a pool arrangement. Utilities attempt to smooth the patterns of electricity usage through peak-load pricing or time-of-day pricing and through other programs to shift the costs of usage toward peak users. Rate regulation constrains such efforts, however. In addition, utilities address the variability of demand through the design of interruptible or curtailable rates that allow industrial users to obtain discounts in return for allowing their load to be dropped if capacity shortages occur during peak periods.

Q. Does the utility's obligation continue after a customer has ceased to subscribe to service?

A. Yes. Suppose a large customer terminates service from the utility and turns either to a competing provider of electricity or to self-generation. The departing customer continues to enjoy the benefits of a service that the utility provides to it: insurance that the customer will be able to rely on the utility to supply service if the customer's alternative source of supply is inadequate. The utility must maintain sufficient capacity to serve the departed customer *if he returns*.

Until he actually returns to the utility, however, the departed customer makes no contribution to recovery of the utility's cost of maintaining standby capacity.

Needless to say, the departed customer makes no contribution to margin with which the utility can recoup losses on services provided below cost to politically preferred constituencies. The departed customer is a free rider, and the remaining customers pay the premium on the insurance that he consumes. That insurance subsidy artificially raises the price of service to remaining customers and makes alternative provision of the utility's service increasingly attractive to the utility's remaining customers, particularly large users.

Q. **In what sense is "excess" capacity currently used and useful?**

A. Given the utility's obligation to serve future demand, it should be clear that available generation capacity is used and useful in conferring a current benefit on consumers apart from their current consumption of power. Current consumers derive a current benefit from the ability of the utility's existing infrastructure to accommodate unexpected peaks in usage or growth in demand. Whether an investment is economically beneficial depends upon a wide variety of factors. Obviously, if current capacity is insufficient to meet demand at prevailing prices and an investment in plant yields added capacity, then the output generated by that added capacity unquestionably constitutes an economic benefit. Where capacity is not in short supply, further analysis may nonetheless reveal that some other form of current economic benefit accrues to utility customers and to the general public from capacity expansion. Those benefits may include greater network reliability and insurance against longer-period capacity shortages resulting from unforeseeable increases in demand. In addition, the availability of capacity at any given moment reflects that technology and other factors make investment inherently "lumpy."

Consumers of electric power currently benefit from all of those possible consequences. Although at first glance it may appear otherwise, a benefit such as the avoidance of capacity shortages is not different in principle from direct financial benefits, such as lower operating costs. Each benefit has a savings in costs that corresponds to and appropriately measures its economic value, even if that value cannot be definitively quantified in monetary terms. For example, consumers clearly benefit if the utility has enough additional generation capacity to reduce the risk of outages and network failure. Provision against risk is a tangible product that is bought and sold in a market at observable prices, as the existence of the insurance industry attests.

The existence of available capacity that reduces risk frees the utility, and ultimately its customers, from the need to bear the costs that would be entailed in incurring those risks. It also frees the utility's business customers from incurring the cost of business-interruption insurance against any financial damages to them arising from a power outage. Each of those burdens has an obvious financial cost whose magnitude can, at least in principle, generally be estimated.

Q. **How does the regulatory contract constrain the utility's freedom to exit markets?**

A. A utility cannot exit a market at will. A utility must secure the regulator's authorization through an abandonment proceeding to withdraw service. Unlike the utility, competitive entrants can abandon any of their facilities at will. The prohibition on abandonment is therefore clearly an incumbent burden, one closely related to the utility's universal service obligation. That burden is substantial because, given rate averaging, the utility is inevitably required to offer some customers service at uncompensatory prices. The prohibition on exit is thus another aspect of the regulatory contract that compels the utility to deviate from subsidy-free prices.

II. Deregulatory Takings

Q. **What is a "deregulatory taking"?**

A. Sweeping deregulation promises to bring the benefits of competition to electricity markets. Those benefits include improvements in operating efficiencies, competitive prices, efficient investment decisions, technological innovation, and product variety. The benefits of competition, however, do not include forced transfers of income from shareholders of utilities to their customers and competitors as a result of asymmetries in regulation. Asymmetric regulation can only serve to impede competition and impair the financial health of incumbent utilities. As regulators dismantle barriers to entry and other regulatory restrictions, they must honor their past commitments and avoid actions that threaten to confiscate or destroy the property of utility investors on an unprecedented scale. Unless accompanied by policies to permit the incumbent utility a reasonable opportunity to recover its full stranded costs, the abrogation of the relationship between the regulator and the utility (whether one chooses to call it a "contract" or not) effects a taking of private property for public use without just compensation. I call that form of confiscation of private property a *deregulatory taking*.

Q. **What are the principal categories of takings cases?**

A. The Supreme Court has placed takings cases into three categories. In declining order of judicial solicitude given the property owner, the categories are physical invasions of property; confiscatory public utility rates; and regulatory takings. All three categories are examined in my article in the *New York University Law Review*. For brevity, I will focus on the first two categories.

A. Physical Invasion of Network Facilities

Q. **What is the controlling case law on takings that arise from physical invasion of**

property?

A. A physical invasion of property compelled by the state gives rise to an absolute right of compensation. The leading decision on takings arising from physical invasion of property is the Supreme Court's 1982 decision in *Loretto* v. *Teleprompter Manhattan CATV Corp.*, 458 U.S. 419, 421 (1982), which defended that rule even in the case of "a minor but permanent physical occupation of an owner's property authorized by government." The Court announced that "when the `character of the governmental action,' is a permanent physical occupation of property, our cases uniformly have found a taking to the extent of the occupation, without regard to whether the action achieves an important public benefit or has only minimal economic impact on the owner." *Id.* at 434–35 (quoting *Penn Central*, 438 U.S. at 124) (citation omitted).

Q. **How did *Loretto* arise?**

A. At issue in *Loretto* was a New York statute that required a landlord to permit a cable television (CATV) company to install its CATV facilities upon her property, subject to payment of no greater than "reasonable" compensation set by a state commission. Exclusively franchised to build the CATV system within certain parts of Manhattan, Teleprompter wired Ms. Loretto's five-story apartment building, for which the commission deemed her to be entitled to a one-time payment of one dollar. Teleprompter's physical invasion of Ms. Loretto's building was minor and consisted of a cable "slightly less than one-half inch in diameter and of approximately 30 feet in length along . . . the roof top," two directional taps on the front and rear of the roof that were four-inch cubes, "two large silver boxes along the roof cables," and the screws, nails, and bolts used to attach those various pieces of infrastructure to the building. *Id.* at 422. (Actually, two buildings were involved, but I have simplified the facts here.)

Q. **How did the Supreme Court in *Loretto* analyze permanent physical invasions of property?**

A. The Court found the fact of physical invasion dispositive. *Id.* at 426 ("a permanent physical occupation authorized by government is a taking without regard to the public interests that it may serve"). Justice Marshall wrote for the majority that "when the physical intrusion reaches the extreme form of a permanent physical occupation, . . . 'the character of the government action' not only is an important factor in resolving whether the action works a taking but also is determinative." *Id.* A physical intrusion by government has "unusually serious character" and, if permanent, is "extreme" and fundamentally different from a temporary physical intrusion. *Id.* Unlike the balancing analysis in a regulatory takings case, "a permanent physical occupation is a government action of such a unique character that it is a taking without regard to other factors that a court might ordinarily examine." *Id.* at 432. The Court likened its rule on permanent physical invasion to a per se rule in antitrust law. *Id.* at 436.

Q. **Under *Loretto*, does the physical magnitude of the invasion of property matter?**

A. No. The Court said that "constitutional protection for the rights of private property cannot be made to depend on the size of the area permanently occupied." *Id.* at 436 n.12. The Court made light of the factual disagreement between the majority and the dissenters over the volume of the cable boxes attached to Ms. Loretto's building. "The displaced volume . . . . [is] not critical: whether the installation is a taking does not depend on whether the volume of space it occupies is bigger than a breadbox." *Id.* at 438.

Q. **What significance did the *Loretto* Court attach to the power of the property owner to exclude others from using his property?**

A. Writing for the majority, Justice Marshall reasoned that a government policy permitting the permanent physical occupation of private property without compensation would be harmful to society as a matter of first principles, and that such considerations animated the precedents upon which the Court relied in *Loretto*. "Property rights in a physical thing," he reasoned, are "the rights 'to possess, use and dispose of it,'" and the government's permanent physical occupation of private property "destroys each of these rights." *Id.* at 435 (quoting United States *v.* General Motors Corp., 323 U.S. 373, 378 (1945)). Justice Marshall noted in particular that "the owner has no right to possess the occupied space himself, and also has no power to exclude the occupier from possession and use of the space. The power to exclude has traditionally been considered one of the most treasured strands in an owner's bundle of property rights." *Id.* at 435–36 (citing *Kaiser Aetna*, 444 U.S. at 179–80; RESTATEMENT OF PROPERTY § 7 (1936)). A powerful economic rationale supports that conclusion, for the power to exclude is a prerequisite to voluntary exchange, allocative efficiency, and investment.

The Court further noted that "the permanent physical occupation of property forever denies the owner any power to control the use of the property; he not only cannot exclude others, but can make no nonpossessory use of the property. Although deprivation of the right to use and obtain a profit from property is not, in every case, independently sufficient to establish a taking, it is clearly relevant." *Id.* at 436 (citing *Andrus* v. *Allard*, 444 U.S. at 66) (citation omitted). The Court emphasized that "an owner suffers a special kind of injury when a stranger directly invades and occupies the owner's property." *Id.*

Q. **Would mandatory retail wheeling, unaccompanied by the simultaneous lifting of incumbent burdens and the imposition of a mechanism to permit full recovery of stranded costs, constitute a taking under *Loretto*?**

A. Yes. Because of the technological and economic complexity of interconnection and unbundling in the electric power industry, it is easy to overlook the obvious: Mandatory interconnection and unbundling constitute a government-ordered, physical invasion of the property of the incumbent utility. Electric utilities have rights of way, poles, conduits, transmission lines, and the like. Indeed, to build that physical infrastructure, an electric utility originally had to acquire the consent of the land owner or, if it was exercising the right of eminent domain, pay just compensation for its taking. *See Loretto*, 458 U.S. at 429, 437. Mandatory interconnection or unbundling requires rivals of the regulated firm to have physical access to its property. The Oregon Supreme Court has recognized that fact and, relying upon *Loretto*, held unanimously in 1995 that the state PUC's order that enhanced service providers be allowed to co-locate their equipment on the premises of incumbent local exchange carriers constituted a physical invasion that violated the Takings Clause. *GTE Northwest, Inc.* v. *Public*

Util. Comm'n of Ore., 321 Ore. 458, 468–77, 900 P.2d 495, 501–06 (1995), *cert. denied*, 116 S. Ct. 1541 (1996). The court emphasized that "the facts that an industry is heavily regulated, and that a property owner acquired the property knowing that it is heavily regulated, do not diminish a physical invasion to something less than a taking." 321 Ore. at 474, 900 P.2d at 504.

Q. **Can a physical invasion of the incumbent utility's property occur when the physical occupation is not visible?**

A. Yes. The first questions of interconnection pricing in modern regulatory experience arose in connection with the sale of "trackage rights" in the railroad industry. By order of the Interstate Commerce Commission, railroad *A* would be allowed to purchase the right to move its trains over tracks owned by railroad *B*, thus extending the geographic reach of railroad *A*'s rail network beyond its own facilities. One can scarcely imagine a more vivid example of physical invasion than freight trains barreling down a stretch of track. In electric power networks, the locomotives are electrons. Like the locomotive operating pursuant to trackage rights, a rival's use of the incumbent utility's transmission and distribution network involves occupying the physical capacity of that infrastructure to deliver a service that competes with the incumbent's.

Q. **How does retail wheeling physically occupy the incumbent utility's property?**

A. As discussed in greater detail in the testimony of PECO witness Greg Cucchi, the wheeling of electricity over transmission lines and distribution grids presents an example of physical movement through a network. The intrinsic physical properties of electricity make electric power different from other network supply systems, such as those for water or gas. Electricity flows through multiple paths of least resistance.

Upon reaching a network of transmission lines with varying impedances, more power will be distributed through wires with smaller impedances. Also, because there exists no economically viable means of storing large quantities of energy, electric power must be produced, transmitted, and instantaneously distributed to meet customer demand, which varies with the time of day and the season of the year. Because of those unique physical properties of electricity, mandatory retail wheeling, and the use of the utility's transmission system to enable sales by alternative suppliers while aimed at fostering competition in the generation of power, would permanently deprive the incumbent local utility of part of its transmission capacity, and would strand some portion of the incumbent's generation capacity—capacity constructed, through massive investments, in reliance upon the terms of the regulatory contract. Furthermore, the incumbent utility would be forced to make available its distribution path for use by a competitor that may become obligated to provide power to the incumbent's former customer. Consequently, the competitor would have the option of using the incumbent utility's capacity at any time the customer requested service.

Q. **When is the compensation paid for a taking of private property "just"?**

A. Economic analysis provides a simple answer: *Compensation for involuntary exchange is just when it is equivalent to the compensation that could be derived from voluntary exchange. See* RICHARD A. EPSTEIN, TAKINGS: PRIVATE PROPERTY AND THE POWER OF EMINENT DOMAIN 182 (Harvard University Press 1985) ("In principle, the ideal solution is to leave the individual owner in a position of indifference between the taking by the government and retention of the property."). That economic reasoning corresponds to the general principle in American constitutional law. *E.g.*, *Olson* v. *United States*, 292 U.S. 246, 255 (1934).

Q. **As an economic matter, what does that rule for just compensation imply for the compensation to which an electric utility would be entitled for the government-mandated physical invasion of it transmission and distribution network?**

A. The utility should receive its full economic cost of permitting a competitor to use its transmission and distribution network. The critical insight to answering that question comes once again from Professor Alchian's classic definition that "the cost of an event is the highest-valued opportunity necessarily forsaken." Armen A. Alchian, *Cost*, *in* 3 INTERNATIONAL ENCYCLOPEDIA OF THE SOCIAL SCIENCES 404, 404 (David L. Sills ed., MacMillan Co. & Free Press 1968). Alchian's definition of cost has become a matter of textbook economics. For example, Professors David Kaserman and John Mayo note: "The economic concept of costs includes the value of all inputs required for production, including the implicit value of those inputs owned by the producer . . . ." DAVID L. KASERMAN & JOHN W. MAYO, GOVERNMENT AND BUSINESS: THE ECONOMICS OF ANTITRUST AND REGULATION 32 (Dryden Press 1995). An activity's full economic costs "include both implicit and explicit costs." *Id.* The direct use of the electric utility's capacity would be its explicit costs, or "the out-of-pocket expenditures on inputs purchased by the firm (which, in the short run, include both fixed and variable inputs)." *Id.* To derive the *full* economic cost to utility of mandatory network access, however, one must add to those explicit costs the activity's implicit costs, which "are defined as the opportunity cost of owned resources, where the term *opportunity cost*, in turn, is defined as the value of a resource in its best alternative use." *Id.* (emphasis in original). As Judge Richard Posner has observed, "Cost to the economist is `opportunity cost'—the benefit forgone by employing a resource in a way that denies its use to someone else." RICHARD A. POSNER, ECONOMIC ANALYSIS OF LAW 6

(Little, Brown & Co. 4th ed. 1992). Similarly, Dr. Joseph Stiglitz, the former Chairman of the Council of Economic Advisers, writes in his textbook that "when rational firms and individuals make decisions—whether to undertake one investment project rather than another, whether to buy one product rather than another—they take into account *all* of the costs, the full opportunity costs, not just the direct expenditures." JOSEPH E. STIGLITZ, ECONOMICS 44 (W.W. Norton & Co. 1993) (emphasis in original).

Just compensation for the government-mandated physical occupation of PECO's network must therefore include both the direct costs of that occupation and the cost to PECO of the opportunities that it consequently forgoes. As Judge Ginsburg recently wrote for the U.S. Court of Appeals for the D.C. Circuit, "agencies that regulate utility rates have recognized `opportunity cost' as a factor to be considered when setting rates designed to cover the actual costs incurred to provide a particular service" and "[e]conomists, too, have argued that opportunity costs should be considered in ratemaking." *City of Los Angeles Department of Airports* v. *United States Department of Transportation*, 103 F.3d 1027 (D.C. Cir. 1997) (citing *Pennsylvania Elec. Co.*, 60 F.E.R.C. ¶ 61,034, 61,120 & n.1 (1992), *aff'd sub nom. Pennsylvania Elec. Co.* v. *FERC*, 11 F.3d 207 (D.C. Cir. 1993); WILLIAM J. BAUMOL & J. GREGORY SIDAK, TRANSMISSION PRICING AND STRANDED COSTS IN THE ELECTRIC POWER INDUSTRY 139 *et seq.* (AEI Press 1995)). The opportunity cost to PECO of mandatory wheeling is the contribution that foregone retail sales of electricity at current rates would make to the recovery of PECO's costs. That amount must be added to the direct cost of a rival firm's electrons occupying PECO's network.

B. Uncompensatory Rates for Public Utilities

Q. **What is the second category of takings cases to which you referred earlier?**

A. The second category of takings jurisprudence refers to cases on confiscatory public utility ratemaking, of which the Supreme Court's decision in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989), is the most prominent recent example.

Q. **Does the *Duquesne* decision answer the takings questions presented if retail wheeling were to produce uncompensated stranded costs for incumbent utilities?**

A. No. A taking occurs if regulatory authorities interfere with the utility's opportunity to earn a fair return on prudently incurred investment to carry out regulatory obligations. Because the state regulates the return that the utility can earn, courts have long considered rate regulation of a utility's property to be subject to the Takings Clause. Uncompensatory rate regulation thus requires compensation of the utility's investors for their forgone expected returns. The major takings cases involving regulated utilities, such as *Federal Power Commission* v. *Hope Natural Gas Co.*, 320 U.S. 591 (1944), and *Duquesne Light Co.* v. *Barasch*, 488 U.S. 299 (1989), do not clearly answer the question of whether the regulator's refusal to allow the utility the opportunity to recover stranded costs is a taking, for those decisions did not address the consequences of deregulation and wholesale abrogation of the regulatory contract in the name of establishing a competitive marketplace.

Q. **How did the *Duquesne* case arise?**

A. In *Duquesne*, the Duquesne Light Co. began making investments in new nuclear power plants. (Several other utilities were involved in *Duquesne*, but for simplicity I refer only to Duquesne.) Those investments were reasonable (prudent) in light of the current costs of different production technologies and expected future demand at the time they were made. Changes in the relative costs and risks of nuclear power (for example, the Three Mile Island nuclear mishap) resulted in a further (prudent) decision to abandon the nuclear power plants. Duquesne had spent roughly $35 million in planning and preparation by that time. 488 U.S. at 302. Duquesne sought to add those sunk costs to its rate base and to recover them through amortization and the allowed rate of return. Unfortunately for Duquesne, however, Pennsylvania enacted legislation after the expenditure but before the inclusion of the nuclear costs in the rate base that foreclosed the Pennsylvania Public Utility Commission from granting Duquesne recovery of those costs though higher utility rates. *Id.* at 303–04. The Court examined whether the state legislation caused a taking of the property of Duquesne's shareholders without just compensation.

Writing for the Court, Chief Justice Rehnquist noted that Duquesne had "a state statutory duty to serve the public" and that its "assets are employed in the public interest," but that the company was "owned and operated by private investors." *Id.* at 307. Those characteristics set the regulated firm apart from others: "This partly public, partly private status of utility property creates its own set of questions under the Takings Clause of the Fifth Amendment." *Id.* Whether the allowed rates of a public utility violate the Takings Clause depends on whether they are "confiscatory." *Id.* at 307–08. The answer to that question, however, does not depend on the use of any single methodology. The *Duquesne* Court reaffirmed the holding in *Hope* that it is the overall effect of rate regulation, not the details or methods, that matter: "[I]t is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unreasonable, judicial inquiry . . . is at an end. The fact that the method employed to reach that result may contain infirmities is not then important." *Hope*, 320 U.S. at 602, *quoted in Duquesne*, 488 U.S. at 310. The question in *Duquesne* then was whether the rate of return that was achieved was constitutionally sufficient. The Court considered the unrecovered sunk costs as part of the investment on which to measure the overall rate of return.

Q. **Why does *Duquesne* fail to answer the takings questions presented if retail wheeling were to produce uncompensated stranded costs for incumbent utilities?**

A. Five facts convinced the Court that no taking of Duquesne's property had occurred. Those facts look very different in the case of breach of the regulatory contract. First, Duquesne did not claim "that the total effect of the rate order arrived at . . . is unjust or unreasonable," and, to the contrary, the Court found that "the overall effect is well within the bounds of *Hope*, even with total exclusion" of the prudently incurred costs for the nuclear plants. *Id.* at 311–12. "The Constitution protects the utility from the net effect of the rate order on its property. Inconsistencies in one aspect of the methodology have no constitutional effect on the utility's property if they are compensated by countervailing factors in some other aspect." *Id.* at 314. In contrast, the total exclusion of stranded costs could bankrupt certain utilities.

Second, Duquesne's "$35 million investment in the canceled plants comprises roughly 1.9% of its total base." *Id.* at 312. Although the Court here did not cite Justice Holmes's remark in *Pennsylvania Coal* about the transactions costs of compensating trivial takings of private property, 260 U.S. at 413, that consideration may have been present. In contrast, the amount of stranded costs at stake for an electric utility such as PECO Energy may exceed the $35 million in *Duquesne* by orders of magnitude.

Third, the denial of cost recovery caused by the opportunistic behavior of the Pennsylvania legislature did not threaten Duquesne's survival:

> No argument has been made that these slightly reduced rates jeopardize

> the financial integrity of [Duquesne], either by leaving [it] insufficient operating capital or by impeding [its] ability to raise future capital. Nor has it been demonstrated that these rates are inadequate to compensate current equity holders for the risk associated with their investments under a modified prudent investment scheme.

488 U.S. at 312. Again, breach of the regulatory contract unquestionably *does* jeopardize the financial integrity of certain electric utilities.

A fourth and related fact upon which the Court relied was the extent to which a public utility's income depended on the consistency of the rate methodology that its regulator employs, and the fact that Pennsylvania had not arbitrarily switched back and forth between methodologies:

> The risks a utility faces are in large part defined by the rate methodology because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks. Consequently, a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions. But the instant case does not present this question.

Id. at 315. Justice Scalia, joined by Justices O'Connor and White, concurred but warned, more forcefully than did Chief Justice Rehnquist's opinion for the majority, that the holding in *Duquesne* would not answer the question of whether just compensation would be due in future takings cases where the nature and magnitude of the utility's prudent investment differed substantially from Duquesne's:

> [W]hile "prudent investment" (by which I mean capital reasonably expended to meet the utility's legal obligation to assure adequate service) need not be taken into account as such in ratemaking formulas, it may need to be taken into account in assessing the constitutionality of the particular consequences produced by those formulas. We cannot determine whether the payments a utility has been allowed to collect constitute a fair return on investment, and thus whether the government's action is confiscatory, unless we agree upon what the relevant "investment" is. *For that purpose, all prudently incurred investment may well have to be counted.* As the Court's opinion describes, that question is not presented in the present suit, which challenges techniques rather than consequences.

Id. at 317 (Scalia, J., concurring) (emphasis added). Breach of the regulatory contract *does* present the serious constitutional question that *Duquesne* did not, for it threatens to exploit the utility's irreversible investment to a far greater extent than does the opportunistic disallowance of costs through prudency reviews or other retrospective mechanisms.

Fifth, the Court understood that "utilities are virtually always public monopolies . . . relatively immune to the usual market risks." *Id.* at 315. New policies mandating retail wheeling, however, would overturn that understanding, for the goal of such policies is to deny current providers of electricity all protection from the "usual market risks" of competition.

In short, although *Duquesne* forced utility investors to bear the losses from *unrecovered but prudently incurred investments in nonsalvageable assets, the Court's* reasoning indicates that the problem of stranded costs arising from breach of the regulatory contract would present a case distinguishable from *Duquesne* in all five respects. An important implication of *Duquesne* is that utility investors must be compensated in one way or another for prudently incurred sunk costs. What is *not* permitted is switching "back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others." *Id.* at 315.

Q. **How would you summarize your testimony?**

A. I have examined whether it would be "just and reasonable" under the Electricity Generation Customer Choice and Competition Act for the Commission to permit PECO Energy full recovery of its stranded costs pursuant to its restructuring. Both economic theory and the economic history of public utility regulation give content to the legal requirements of the "just and reasonable" standard of sections 2804(13), 2804(14), and 2808 of the Act. That economic analysis supports my conclusion that it would be "just and reasonable" under the Act for the Commission to permit PECO Energy full recovery of its stranded costs. Historical evidence substantiates the existence of a "regulatory contract," and compelling economic arguments confirm the need for such a contract between the electric utility and the state. A Pennsylvania utility expected, under traditional regulatory practice, to receive a reasonable opportunity to earn revenues sufficient to recover all of its prudently incurred investments and a competitive return on those investments. Pennsylvania would breach its regulatory contract with PECO Energy if the Commonwealth were to order retail wheeling without allowing PECO Energy to achieve full recovery of the stranded costs of its prudently incurred investments. Moreover, a failure by Pennsylvania to allow PECO

Energy such recovery would effect a taking of property under the Fifth Amendment of the U.S. Constitution.

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

A. Yes.

APPENDIX: PROFESSIONAL QUALIFICATIONS

Q. **Please state your professional qualifications and educational background.**

A. I am the F. K. Weyerhaeuser Fellow in Law and Economics at the American Enterprise Institute for Public Policy Research (AEI), where I direct AEI's Studies in Telecommunications Deregulation and AEI's Studies in Postal Regulation. I am also a senior lecturer at the Yale School of Management, where I teach a course on telecommunications regulation with Professor Paul W. MacAvoy. I am a member of the board of editors of the *Journal of Economics and Management Strategy*, published by the MIT Press.

I have served in two positions in the federal government. From 1987 to 1989, I was Deputy General Counsel of the Federal Communications Commission. From 1986 to 1987, I was Senior Counsel and Economist to the Council of Economic Advisers in the Executive Office of the President, where I assisted in writing the *Economic Report of the President 1987* and participated in Cabinet-level working groups assessing federal policies concerning the regulated network industries.

My academic research concerns regulation of network industries, antitrust policy, and constitutional law issues concerning economic regulation. I have published three books concerning pricing, costing, competition, and investment in regulated network industries: *Transmission Pricing and Stranded Costs in the Electric Power Industry* (AEI Press 1995), co-authored with William J. Baumol; *Toward Competition in Local Telephony* (MIT Press & AEI Press 1994), also co-authored with Professor Baumol; and *Protecting Competition from the Postal Monopoly* (AEI Press 1996), co-authored with Daniel F. Spulber. A fourth book of mine, *Deregulatory Takings and the Regulatory Contract*, also co-authored with Professor Spulber, is forthcoming from the Cambridge University Press in 1997. That book, like my book on stranded costs with Professor Baumol, is directly relevant to the issues in this proceeding.

In addition to having published books of direct relevance to this proceeding, I am the author of *Foreign Investment in American Telecommunications* (University of Chicago Press 1997), and of more than twenty-five scholarly articles in the *Journal of Political Economy, California Law Review, Columbia Law Review, Cornell Law Review, Duke Law Journal, Georgetown Law Journal, Harvard Journal on Law & Public Policy, New York University Law Review, Northwestern University Law Review, Southern California Law Review, Yale Journal on Regulation*, and in more popular publications such as the *National Law Journal, Public Utilities Fortnightly, Regulation*, and the *Wall Street Journal*. A 1996 survey ranked me among the fifty most prolific authors of articles published in the twenty most frequently cited law reviews. I have testified before the U.S. Senate and House of Representatives, and my writings have been cited by the Supreme Court, by the lower federal courts, by state and federal regulatory commissions, and by the Judicial Committee of the Privy Council of the House of Lords. I have been a consultant on regulatory and antitrust matters to the Antitrust Division of the U.S. Department of Justice, to the Canadian Competition Bureau, and to more than thirty companies in the electric power, telecommunications, natural gas, mail delivery, and computer software industries in North America, Europe, Asia, and Australia.

I received A.B. and A.M. degrees in economics and a J.D. from Stanford University, where I was a member of the *Stanford Law Review*. I served as a law clerk to Chief Judge Richard A. Posner during his first term on the U.S. Court of Appeals for the Seventh Circuit.

Q. **Please list your previous testimony in regulatory proceedings or on regulatory**

matters.

A. I have provided testimony in the following matters:

1. Affidavit of J. Gregory Sidak and Daniel F. Spulber, appended to Comments of the United States Telephone Association *in* Usage of the Public Switched Network by Information Service and Internet Access Providers, Notice of Inquiry, Federal Communications Commission, CC Dkt. No. 96-263 (filed Mar. 24, 1997).

2. Reply Affidavit of J. Gregory Sidak and Daniel F. Spulber, appended to Reply Comments of the United States Telephone Association *in* Access Charge Reform; Price Cap Performance Review for Local Exchange Carriers; Transport Rate Structure and Pricing; Usage of the Public Switched Network by Information Service and Internet Access Providers, Notice of Proposed Rulemaking, Third Report and Order, and Notice of Inquiry, Federal Communications Commission, CC Dkt. Nos. 96-262, 94-1, 91-213, 96-263 (filed Feb. 14, 1997).

3. Affidavit of J. Gregory Sidak and Daniel F. Spulber, appended to Comments of the United States Telephone Association *in* Access Charge Reform; Price Cap Performance Review for Local Exchange Carriers; Transport Rate Structure and Pricing; Usage of the Public Switched Network by Information Service and Internet Access Providers, Notice of Proposed Rulemaking, Third Report and Order, and Notice of Inquiry, Federal Communications Commission, CC Dkt. Nos. 96-262, 94-1, 91-213, 96-263 (filed Jan. 29, 1997).

4. Testimony of J. Gregory Sidak on behalf of GTE South Inc., Petition of AT&T Communications of the South Central States, Inc., for Arbitration of Certain Terms and Conditions of a Proposed Agreement with

GTE South Inc. Concerning Interconnection and Resale Under the Telecommunications Act of 1996, Case No. 96-478, Public Service Commission of Kentucky (Jan. 14, 1997).

5. Cross Examination Testimony of J. Gregory Sidak on behalf of GTE North Inc., In the Matter of Sprint Communications Company L.P.'s Petition for Arbitration of Interconnection Rates, Terms, Conditions and Related Arrangements with GTE North Inc., Case No. 96-10210-TP-ARB, Public Utilities Commission of Ohio (Nov. 21, 1996).

6. Testimony of J. Gregory Sidak on behalf of GTE South Inc., Petition of MCI, Public Service Commission of Kentucky (Nov. 12, 1996).

7. Direct Testimony of J. Gregory Sidak on behalf of GTE North Inc., Petition of Sprint, Public Utilities Commission of Pennsylvania (Nov. 7, 1996).

8. Direct Testimony of J. Gregory Sidak on behalf of GTE Midwest Inc., Petition of MCI, Public Utilities Commission of Indiana (Nov. 1, 1996).

9. Direct Testimony of J. Gregory Sidak on behalf of GTE Midwest Inc., *AT&T Communications of the Midwest Inc.* v. *GTE Midwest Inc.*, Iowa Utilities Board, Dkt. No. ARB-96-3 (Oct. 15, 1996).

10. Direct Testimony of J. Gregory Sidak on behalf of GTE North Inc., Petition of AT&T, Public Utilities Commission of Pennsylvania (filed Sept. 9, 1996).

11. Affidavit of J. Gregory Sidak, appended to Memorandum of Law in Support of Petition of the Energy Association of New York State in *Energy Association of New York State* v. *Public Service Commission of the State of New York*, Index No. 5830-96 (filed Supreme Ct. N.Y., County of

Albany, Sept. 18, 1996).

12. Rebuttal Testimony of J. Gregory Sidak on behalf of Central Power and Light Company *in* Application of Central Power and Light Company for Authority to Change Rates, Competitive Issues Phase, Public Utility Commission of Texas, SOAH Dkt. No. 473-95-1563, PUCT Dkt No. 14965 (filed Aug. 1, 1996).

13. Reply Affidavit of J. Gregory Sidak, appended to Reply Comments of the United States Telephone Association *in* Allocation of Costs Associated with Local Exchange Carrier Provision of Video Programming Services, Federal Communications Commission, CC Dkt. No. 96-112 (filed June 12, 1996).

14. Affidavit of J. Gregory Sidak, appended to Comments of the United States Telephone Association *in* Allocation of Costs Associated with Local Exchange Carrier Provision of Video Programming Services, Federal Communications Commission, CC Dkt. No. 96-112 (filed May 31, 1996).

15. Affidavit of Michael J. Doane, J. Gregory Sidak, and Daniel F. Spulber, appended to Reply Comments of GTE Service Corporation *in* Implementation of the Local Competition Provisions in the Telecommunications Act of 1996, Federal Communications Commission, CC Dkt. No. 96-98 (filed May 30, 1996).

16. *An Empirical Analysis of the Efficient Component-Pricing Rule and Sections 251 and 252 of the Telecommunications Act of 1996*, appended to Comments of GTE Service Corporation *in* Implementation of the Local Competition Provisions in the Telecommunications Act of 1996, Federal Communications Commission, CC Dkt. No. 96-98 (filed May 16, 1996), co-authored with Michael J. Doane and Daniel F. Spulber.

17. *Technological, Environmental and Financial Issues Raised by Increasingly Competitive Electricity Markets, Hearings before the Subcommittee on Energy and Power of the House Committee on Commerce,* 104th Congress, 2d Session (Mar. 28, 1996).

18. *Monopoly and the Mandate of Canada Post*, in Submission of the Director of Investigation and Research, Competition Bureau, to Canada Post Corporation Mandate Review Committee (Ottawa, Feb. 15, 1996).

19. Reply Comments of J. Gregory Sidak, Market Entry and Regulation of Foreign-affiliated Entities, Notice of Proposed Rulemaking, Federal Communications Commission, IB Dkt. No. 95-22 (filed May 12, 1995).

20. Comments of J. Gregory Sidak, Market Entry and Regulation of Foreign-affiliated Entities, Notice of Proposed Rulemaking, Federal Communications Commission, IB Dkt. No. 95-22 (filed Apr. 11, 1995).

21. *Competition and Regulatory Policies for Interactive Broadband Networks*, in Competition Policy, Regulation and the Information Economy: Submission of the Director of Investigation and Research, Bureau of Competition Policy, to the Canadian Radio-television and Telecommunications Commission, Public Notice CRTC 1994-130, Order in Council P.C. 1994-1689 (Ottawa, Jan. 16, 1995), co-authored with Robert W. Crandall.

PECO STATEMENT NO. 11

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY

OF

JOSEPH F. BRENNAN

Regarding the Development of the Cost Rate for Common Equity, Overall Rate of Return, and an Overall After-Tax Discount Rate Employed to Compute Stranded Investment

TABLE OF CONTENTS

DIRECT TESTIMONY OF JOSEPH F. BRENNAN

I. QUALIFICATIONS

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

A. My name is Joseph F. Brennan. I am Chairman of the Board of AUS Consultants. My business address is P.O. Box 1050, Moorestown, New Jersey 08057-1050.

Q. **Please provide a summary of your education and experience.**

A. A summary of my education and experience is contained in Appendix A supplementing my direct testimony. I have previously testified as an expert witness on rate of return and other disciplines before over 30 state public utility commissions and several federal regulatory agencies. I have testified on behalf of investor-owned companies, municipalities, regulatory agencies, and governmental bodies.

Q. **Please briefly describe the work performed by AUS Consultants.**

A. AUS Consultants (AUS) is an independent consulting firm. It is comprised of several groups offering services in utility ratemaking, valuation, market research, industry analysis, and utility financial publishing.

The Utility Services Group specializes in every aspect of ratemaking, including rate of return, depreciation, cost of service, tariff design, valuation, demand-side management, lead/lag studies, and ratemaking accounting. Services have been performed for natural gas, electric, telephone, water, wastewater, cable television, maritime shipping, railroad, bus transportation, steam heating, and other enterprises whose price of service is established by a governmental or regulatory body.

The Valuation Group values tangible assets, intellectual property, intelligence transfer, provides fairness opinion in conjunction with mergers and acquisitions, and values utility property for ad valorem tax purposes. The services are performed for many national and multinational companies and public utilities.

The Market Research Group is the 30th largest market research operation in the country. This Group conducts the ABC News/Washington Post poll, performs surveys for utilities and non-utilities such as the Associated Press and Merrill Lynch and performs customer satisfaction surveys for, among others, AT&T.

C.A. Turner Utility Reports publishes on a monthly, quarterly, and annual basis utility financial data concerning approximately 200 public utilities whose common stock is traded to thousands of subscribers which include utilities, regulators, individuals, brokerage firms, lawyers, and libraries. In addition, C.A. Turner, under a license agreement, publishes the American Gas Association Rate Service, which is a tabulation of the rates for service, including transportation rates, charged by approximately 300 local gas distribution company members of the AGA.

The Industry Analysis Group is engaged in transmission pricing, alternate ratemaking strategies, IPP contract renegotiation, economic analysis and forecasting, market segmentation studies, stranded investment analysis, studies involving market share and market dominance as well as agriculture and steel economic analyses.

AUS Consultants maintains its principal offices in Mount Laurel, New Jersey (Moorestown Post Office); Media and Harrisburg, Pennsylvania; and Milwaukee, Wisconsin. Satellite offices are also maintained in Boca Raton and Punta Gorda, Florida as well as Chicago, Illinois and New York City. AUS employs about 150 full-time and 250 part-time people.

Q. **Have you prepared an exhibit to accompany your direct testimony?**

A. Yes. Exhibit JFB-1, comprised of 21 schedules, has been prepared by me or under my direct supervision.

II. PURPOSE

Q. **What is the nature of your assignment in this proceeding?**

A. I was engaged by PECO Energy Company (PECO or the Company) to estimate the cost rate of common equity, the overall rate of return and the related overall after-tax discount rate to be employed to compute the amount of stranded investment.

In addition, I was asked by PECO to respond to the argument, which has been expressed elsewhere, that electric utility investors were aware of and have been compensated in the past for the prospective loss of stranded cost recovery.

Q. **Do you adhere to certain generally-accepted principals in arriving at a recommended overall cost of capital?**

A. Yes.

Q. **Please explain.**

A. The overall cost of capital should be company-specific to the extent possible with respect to capital structure, related ratios, and capital cost rates. In addition, since market data are essential to the determination of an estimate of an investor-required cost of common equity, the cost of common equity should be derived from market information. The cost of equity is not what theorists, regulators or company management believe it should be, or what they would like it to be, but what the money markets say it is. Since capital is raised in the money market, the relevant information to study and analyze is information derived from the money market. A utility has no monopoly in the money market. Capital cannot be conscripted.

In my opinion, only if market data are employed can the regulator ensure, over the long run, the utility's ability to meet its service obligations. Assurance of adequate service can only be achieved if earnings are sufficient to permit: (1) the attraction of an adequate amount of capital at a reasonable cost; (2) the maintenance of the integrity of presently invested capital; and (3) a return on common equity commensurate with returns on investments in other enterprises having corresponding risks. These standards for a fair rate of return have been well established by the U.S. Supreme Court in the Bluefield Water Works and Improvement Company v. Public Service Commission, 252 U.S. 679 (1922) and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

Regulatory authorities must function as a substitute for the marketplace in setting the price of capital employed by a utility consistent with the need to provide service over the long term. Therefore, prices should be set to provide the utility with an opportunity to recover all costs, including a fair return to equity investors.

My opinion in support of a proposed overall rate of return is that this proposed rate is consistent with (a) the requirement to attract an adequate amount of capital at a reasonable cost in competition with similar risk enterprises, (b) the ability to maintain the integrity of presently invested capital, and (c) the need to provide a return on common equity commensurate with returns on investments in other enterprises having corresponding risks. My reasons and opinion supporting this statement are set forth hereinafter.

III. SUMMARY

Q. **What is your recommendation?**

A. I recommend an overall rate of return of 10.05% and a related after-income tax discounted weighted cost rate of 8.41%. In arriving at this overall rate of return, I included an 11.60% common equity cost rate. As I will explain later in my testimony, the 11.60% common equity cost rate and hence the overall rate of return and the related after-income tax weighted discount rate may be conservatively low and may require updating prior to the close of the record in this case. The ratemaking capital structure ratios I employed are the December 31, 1996 PECO ratios of 43.1% long-term debt, 3.3% MIPS debt, 3.0% preferred stock, and 50.6% common equity. The capital structure, related ratios and debt and preferred stock cost rates were provided to me by PECO.

The estimate of the market-required cost rate for common equity capital of 11.60% is PECO-specific and is the product of an independent study I performed. I also performed an independent study based upon information pertaining to barometer group companies of similar, but not identical, investment risk as one check of the appropriateness of the common equity cost rate included in my overall rate of return recommendation. The average estimated market-required cost rate for common equity appropriate for the barometer group companies of similar, but not identical, investment risk is 11.30%. I also observed other financial information and performed other calculations as a check on the reasonableness of my estimate of the common equity cost rate included in my overall rate of return recommendation as I will explain later in my testimony. A summary of my calculations as to the overall rate of return and the after-tax discount rate is shown on Schedule 1. A summary of the development of the cost rate for common equity capital is shown on Schedule 2.

With respect to the argument that electric utility investors were aware of and have been compensated in the past for the prospective loss of stranded investment cost recovery as I will explain, the evidence overwhelmingly indicates there is no support for such a belief. This is particularly true for PECO. PECO has earned less than the electric industry in general and less than intended by this Commission. In addition, a very large part of PECO's reported earnings are not the product of cash collected from consumers, but instead the product of required non-cash bookkeeping entries. Moreover, investors in PECO, in particular, had no reason to believe installed plant recognized in rates authorized by this Commission would become stranded and that there was a possibility of non-recovery of investor-provided plant, until very recently.

IV. RISK EVALUATION

Q. **Is it necessary to analyze risk in the determination of the appropriate cost rate for common equity capital?**

A. Yes.

Q. **What risk factors affect investor judgment?**

A. There are two principal factors, business risk and financial risk. The sum of business risk and financial risk is commonly referred to as investment risk. Business risk encompasses all the risks of a firm as if it were financed entirely with common equity capital. Financial risk is the added element of risk to the common stock investor resulting from the employment of debt and preferred stock. The presence of debt and preferred stock in the capital structure provides what is referred to as financial leverage and obviously increases the risk to common stockholders since debt and preferred stock investors have a claim prior to common stock investors with regard to earnings and assets.

Q. **Is there an interrelationship between business and financial risk?**

A. Yes, in the sense that the amount of business risk present in an enterprise influences the manner in which that enterprise should be financed over time. A higher degree of business risk generally requires the employment of less financial leverage, i.e., less debt and preferred stock and more common equity. For clarification, it should be noted that it is not possible, nor is it necessary, at all times for any entity to maintain whatever is considered the appropriate capital structure mix of debt and equity.

Company-specific risks can be affected by such factors as the character of the economy of the territory served by the utility; the risk of rate regulation itself; the need for and magnitude of capital expenditures; generation, revenue, and sales mix, and competition. Collectively, any of these risks could result in an investor perception of an investment risk for a particular utility which is more or less than the conventional wisdom suggests. In the final analysis, the judgment of the appropriate capital structure ratios as well as cost rate for common equity capital for ratemaking purposes for any utility must be the product of a company-by-company analysis to the extent possible.

Q. **Is there evidence that the capital marketplace gives recognition to these risk perceptions?**

A. Yes, the capital marketplace is driven by investor perceptions of risk. One of the best examples is bond ratings. Rating agencies, such as Standard & Poor's (S&P), evaluate the creditworthiness of the fixed income securities of many businesses.

These ratings reflect perceptions of the relative risk associated with a particular security of a particular company in a particular industry. The criteria for S&P ratings are generally known and involve consideration of factors relating to both the business and financial risk of the issuing company.

Investors rely upon the qualitative judgments of the rating agencies, as evidenced by the prices they pay for variously rated bonds. Investors require higher returns for bonds of lower quality (high risk) and lower returns for those of higher quality (low risk).

In addition to long-term debt ratings, there are a number of financial ratios and statistical data that can be employed to gain insight as to the relative risk of one enterprise compared with another.

Q. **Why is your common equity cost rate recommendation the product of PECO-specific information rather than information also pertaining to the barometer groups?**

A. There are no two companies or average of any group of companies identical in all regards as to the investment risk of a particular single company. Accordingly, when there is available market information regarding the common stock of the company whose common equity cost rate is to be estimated, the best estimate is the product of market data pertaining to that company. The average estimate derived from a barometer group should be used as a check.

Q. **What criteria did you employ in the selection of the barometer group of companies included in your study?**

A. I employed several criteria, which are: (1) companies with an S.I.C. Code of 4911 (Electric Services) or 4931 (Electric and Other Services Combined); (2) companies with common stock which is actively traded; (3) companies which operate in the Northeastern, Great Lakes, North Central, South Central, or Southeastern region of the continental United States (in conformance with the most recent regional groupings made by the Federal Energy Regulatory Commission's Bureau of Power); (4) companies with 1995 permanent capital of at least $2 billion; (5) companies with at least 70% of their 1995 operating revenues derived from electric operations; (6) companies with a Moody's Investors Service (Moody's) bond rating of A3, Baa1, or Baa2 or an S&P bond rating of A-, BBB+, or BBB; and (7) companies which have paid common dividends and have not cut their common dividends since 1992.

These criteria led to a nine company barometer group. I consider a nine company group to be sufficient in number to avoid distortion caused by any one single company if the group were significantly smaller than nine.

I have analyzed the financial and operating characteristics of the nine company group. As I will explain later, in some regards the average barometer group company is less investment risky than PECO and in other regards, more investment risky than PECO. On balance, I believe the average investment risk for the group is slightly less than PECO.

Q. **Do you believe the management of a utility should have the right to choose the type of capital it will employ to finance its investment in assets?**

A. Yes. I believe management should have the right to choose the way its assets are financed. My opinion extends to public utility companies with the caveat that management's choice should be employed by the regulatory agency having jurisdiction with respect to establishing the authorized price of service, so long as management's choice is reasonable and prudent and is reasonably representative of the ratios expected to be employed. PECO's capital structure ratios meet these standards at this time.

V. METHODOLOGY EMPLOYED TO ESTIMATE COMMON EQUITY COST RATE

Q. **What methods did you employ in arriving at your 11.6% PECO common equity cost rate recommendation?**

A. I employed two market methods, namely, the Discounted Cash Flow (DCF) and the

Capital Asset Pricing Model (CAPM). In forming my opinion, I gave equal weight to the results derived from each of these methodologies.

Q. **Why did you employ more than one method?**

A. Every available method requires the exercise of judgment. Therefore, no one method should be employed to the exclusion of any other method in arriving at a judgment as to what is the market-required cost rate for common equity capital. One of the most commonly used methods employed by regulatory agencies to arrive at a judgment of the market-required common equity cost rate is the constant growth DCF model. As I will explain later, there is reason to believe that a *constant growth DCF model produces results that may be less than reliable.* Further, I am not aware of any empirical evidence proving that investors use DCF exclusively or that even a majority of investors rely primarily upon DCF. Moreover, a compilation of methods employed by regulatory commissions published by the National Association of Regulatory Utility Commissioners (NARUC) for 1995-1996 reveals that an overwhelming majority (about 80%) of commissions, including the Pennsylvania Public Utility Commission (PUC), do not employ just DCF in arriving at the regulatory-determined opportunity cost rate for common equity capital, but instead most often employ a variety of methods.

I do not mean to suggest by these comments that methods other than DCF, such as CAPM, are completely reliable or that other methods are not used by investors. Indeed, as I will discuss later, as with DCF, the CAPM is not completely reliable. It is for this reason that a variety of methods should be employed to minimize estimating error.

VI. DATA UNDERLYING COMMON EQUITY COST RATE RECOMMENDATION

Q. **What financial data and ratios have you observed in formulating an opinion as to the cost rate for common equity capital?**

A. I have observed a myriad of financial data including, but not limited to, interest rates, both past and forecast, the present and past achieved rate of return on average book common equity, market-to-book ratios, data related to stock price movements, earnings/price ratios, dividend payout ratios, dividend yield, effective income tax rate, internal cash generation as a percent of gross construction, AFUDC as a percent of income available for common equity, before-income tax interest coverage, operating statistics regarding generation, revenue, KWH sales, customer mix and sales growth, bond ratings, evaluation of regulatory climate, authorized returns on common equity, and common stock rankings. These data are shown on Schedules 3 through 14, inclusive.

Q. **Please describe some of the information shown on Schedules 3 through 14, inclusive.**

A. On Schedule 3, I have shown a comparison of interest rates for long-term debt rated Aaa, Aa, A, and Baa. This historical information begins in 1955, the last year in which there was no inflation, and for each year thereafter and for the years 1995 and 1996. by month, as well as the average for those years, and for 1997 for the months of January, February and through March 13, 1997. The information compares yields for public utility debt similarly rated to industrial debt and the spread between the two. Please observe that at March 13, 1997, public utility bonds rated Baa by Moody's were priced to yield 8.30%, or 17 basis points higher than industrial companies whose long-term debt is similarly rated. On page 3 of Schedule 3, I have shown forecasts published by Value Line Investment Survey (Value Line), S&P, and Blue Chip Financial Forecasts for several items including A rated public utility bonds and Treasury bonds. Please note that the three forecasts with respect to Treasury bonds ranged from a low of 6.6% to a high of 7.2% and the average of the three estimates is approximately 6.8%.

On Schedule 4, I have shown the rate of return on average book common equity for PECO and the average for the nine barometer group companies at a spot moment in time in 1997 and for each of the five-year periods ending 1995 and 1990, respectively. At the moment, PECO's rate of return on average book common equity is 11.0%, or slightly lower than the average for the barometer group.

On Schedule 5, I have shown the market-to-book ratios for PECO and the average for the barometer group for the same period of time regarding the information shown on Schedule 4. Please note that at the moment, PECO's market-to-book ratio is just about equal to book value, whereas the market-to-book ratio for the average nine barometer group companies is just under 144%.

On Schedule 5, page 2, I have shown the Dow Jones Industrial (DJI) and the Dow Jones Utility (DJU) averages and the average yield on A rated public utility bonds for official turning points in business cycles from January 1962 to March 1997. Please note that the DJI index increased 136% by March 1997 from the trough of March 1991 or the end of the last recession. Please also note that the DJU average during that same period of time increased but 3.3%. These data suggest the investment risk gap between utilities and non-utility companies has narrowed or perhaps for some utilities closed in the 1990's.

On Schedule 6, I have shown earnings/price ratio information for PECO and the average barometer group company. The period of time again is the same with respect to the information shown on Schedules 4 and 5. Please observe that the current earnings/price ratio for PECO is 10.9% compared to but 8.1% for the average barometer group company. It should be noted that an earnings/price ratio is most often a partial indication of the indicated required market return rate to attract common equity. It is a partial indication because the price reflects expected future earnings, but the earnings used in the computation are historical.

On Schedule 7, I have shown dividend payout and dividend yield information again for the same period of time revealed on Schedules 4, 5 and 6.

Please observe that at this moment in time, the current PECO yield is 8.8% compared with but 6.2% for the average barometer group company. The payout ratios are similar. For the five years ended 1995, the PECO yield was lower than the average barometer group company, but for the five years ended 1990, the PECO yield was considerably higher than the yield for the average barometer group companies. Dividend yields are a function of expected growth in earnings and dividends. When there is a somewhat dramatic change in yield, typically it is accompanied by a rather significant anticipated decrease in growth rates for earnings. Thus, the indicated market-required cost rate for common equity capital may be understated based upon a DCF computation if one reaches back too far to derive a presumed prospective dividend yield based upon the price of stock a year ago and to obtain a dividend yield, particularly if those stale market prices reflected an expected earnings or dividend growth different from the current estimate of earnings or dividend growth. The end result is an understated DCF-derived estimate of the market-required common equity cost rate.

On Schedules 8 and 9, I have shown for each of the five years ended 1995, the total amount of capital employed, the indicated long-term debt and preferred stock cost rates, the capital structure ratios, interest coverages, and other significant financial ratios related to PECO and the average for the barometer group companies, respectively. As can be seen by referring to Schedules 8 and 9, PECO's total capital employed at book value is just under $10 billion, while the average for the barometer group companies is just under $7 billion. At these levels, size does not impact the cost rate for capital. Please also note that the PECO capital structure ratios are very similar to the capital structure ratios employed by the average barometer group company and for the five years ended 1995, the average indicated before-income tax interest coverage relative to long-term debt was identical, although for the most recent year for which information is available for all companies, 1995, PECO's before-income tax interest coverage was slightly better at 3.5 times compared with 3.3 times for the average barometer group company.

On page 3 of Schedule 9, I have shown the average bond rating for the barometer group companies both with respect to Moody's and S&P. For Moody's, the average bond rating is Baa1 and for S&P, it is BBB+. These average ratings are identical to the current PECO ratings relative to long-term debt.

On Schedule 10, I have shown a variety of statistical data comparing PECO and the average for the barometer group companies for the most recent year for which information is available for all companies, namely, the year ended December

31, 1995. Please note that both PECO and the average barometer group company derive more than 90% of their revenues from electric operations and their annual kilowatt hour sales are similar, and they serve similar numbers of customers. Please also note that in terms of generating mix, PECO's mix includes just under 69% nuclear, whereas the average barometer group company's nuclear generation is just over 26%. Generation mix, of course, is but one element of risk assessed by investors when establishing the price of stock.

As can be seen by referring to page 3 of Schedule 10, PECO's revenues derived from industrial customers is just over 30%, whereas the average for the barometer group companies is just under 22%. Even if there were not the threat of competition in the very near-term future, all else equal, PECO may be considered more business risky, given that industrial load is historically more volatile than residential load.

As can be seen by referring to page 5 of Schedule 10, the percent increase in kilowatt hour sales for residential, commercial, and industrial customers is significantly greater for the average barometer group company compared with PECO. All else equal, this would suggest that PECO's service territory, economically speaking, and hence PECO itself, has less prospect for growth than the average barometer group company and PECO is more business risky.

As can be seen by referring to the information on Schedule 11, S&P believes that PECO's business position is somewhat below average, whereas the average for the barometer group companies is average.

The information on Schedule 12 reveals an evaluation of regulatory climate for PECO that is slightly less favorable than the regulatory climate in which the average barometer group company operates. Again, by this yardstick, all else equal, PECO is more business risky compared to the average barometer group company.

The information shown on Schedule 13 compares the present authorized return on common equity for PECO and the average barometer group company. This information has limited use given that awards by regulatory authorities are not all from the same date or vintage.

The information shown on Schedule 14 is a comparison of the S&P common stock ranking and the Value Line Safety Ranking for PECO and the average for the barometer group companies. The average ranking for the barometer group companies is slightly better than the ranking for PECO. However, the Value Line Safety Ranking for PECO is slightly better than the average barometer group company.

VII. DEVELOPMENT OF COMMON EQUITY COST RATE

A. DCF Method

Q. **Briefly describe the constant growth DCF model.**

A. The constant growth DCF model is based upon an analysis of publicly traded common stock. The DCF theory holds that an investor who agrees to purchase common stock at a given market price is purchasing the rights to an infinite income stream. That income stream includes the present and anticipated earnings, the portion of those earnings that are currently and prospectively being paid out in the form of dividends, and the proceeds from the ultimate sale of the stock at some future market price.

Implicit in the investor's decision to buy is the assumption that the investor considers the magnitude of that income stream, the rate at which those earnings and dividends are expected to grow, and the ultimate selling price of the stock. The investor also considers the quality of that income stream; that is, the likelihood that expectations will, in fact, be realized.

Q. **Why is it improper to rely solely upon the DCF method to estimate the market *required cost rate for common equity?***

A. The behavior of investors and thus the market as a whole is at odds with the required assumptions of the DCF model.

Q. **Does the DCF model require the assumption that stock price change is proportionate with the change in earnings and dividends, and dividend payout ratios remain constant over an infinite time horizon?**

A. Yes.

Q. **Are you aware of any evidence that stock price change is proportionate to change in earnings and dividends and the dividend payout ratios remain constant over an infinite investment horizon?**

A. No. My studies reveal stock price change is different than the change in earnings or dividends over any period of time and future dividend payout ratios do not remain constant. Further, based on recent turnover ratios (dividend common shares outstanding divided by common shares traded), the investment horizon for PECO and the average barometer group company investor is little more than 2 years rather than infinite. That information is shown on Schedule 5, page 3.

Q. **What might explain why investor behavior is at odds with the required DCF assumption of proportionate growth in share price and earnings and dividends?**

A. Share price change is also driven by factors not reflected in the DCF model. For example, investors may expect a change in price-earnings multiples. There is no place in the DCF model to reflect an investor-expected change in price-earnings multiples. Yet most financial publications, such as the Wall Street Journal, publish price-earnings multiples as well as dividend yields undoubtedly because investors take into account price-earnings multiples in their buy-sell decisions.

Investor judgments of long range (beyond five years - the maximum earnings or dividends forecast period available to investors) changes in earnings or dividends or in the price earnings multiple are also not captured by the DCF model.

Q. **Since the DCF model requires the assumption of an infinite growth rate, but forecasts published and available to investors are not infinite, how do rate of return witnesses develop their DCF cost rates for common equity?**

A. A rate of return witness attempting to employ the DCF model must exercise subjective judgment that either historical data will be a mirror image of the future or forecasts reaching out but five years will be a mirror image of the infinite future or both. Even if a DCF practitioner possessed divine wisdom to know precisely what growth rate investors had in mind for an infinite period of time, the DCF model would still be an incomplete explanation of the rate of return reflected in the price of stock if an investor also takes into account the other forces at work that affect stock prices such as price-earnings multiple changes, asset values changing due to whole or partial deregulation, etc.

Q. **Is there academic support for the opinion that the DCF model is not reliable?**

A. Yes. The basic market assumptions underlying the DCF model have been questioned seriously in the financial literature. A review of the literature indicates that DCF may provide an incomplete and often inaccurate representation of the overall equity market and of the equity market for regulated public utility companies. The validity of the DCF formula as a measure of the cost of equity capital depends on the validity of the Efficient Market Hypothesis (EMH). EMH postulates a specific model of equity market behavior (the basic DCF model) which, if correct, implies that the equity markets would be efficient. However, the literature is replete with demonstrations that the EMH is not confirmed by actual market behavior. For example, an analysis performed by Eugene Fama illustrates the point (Eugene F. Fama, "Stock Returns, Expected Returns, and Real Activity", the Journal of Finance, Volume XLV, No. 4, September 1990, pp. 1089-1108). Indeed, Dr. Fama indicates that one might be concerned that a relatively small percent of market behavior is explained by the model. This suggests that either the model is incomplete or the market is not efficient.

Q. **Is it true that the DCF model popularized by Professor Myron Gordon proceeded**

from the premise that sustainable growth (b x r) was the appropriate growth rate to employ for DCF calculation purposes?

A. Yes. In his book, The Cost of Capital to a Public Utility, (Division of Research, Graduate School of Business, Michigan State University, East Lansing, MI, 1974), Dr. Gordon reported a test of the b x r sustainable growth rate to which he added a term representing the rate at which equity grows as a result of new stock issuances. Based on electric utility data for the period 1958-1968, Dr. Gordon concluded that his sustainable growth formulation ((b x r) + (s x v)) was superior to the growth rates based on historical data. However, he did note that investors, when forecasting growth, may place some reliance on historical growth. He said, "Finally, it appears that security analysts use past growth in earnings more than any other variable to forecast future growth." This indicates to me that even then Dr. Gordon had some reservations and was reluctant to embrace the sustainable growth rate as being clearly superior.

The tests that Dr. Gordon performed at that time did not directly compare forecasted growth with actual achieved growth. The tests he did employ sought to explain dividend yield. Dr. Gordon's hypothesis was that other things being equal, the dividend yield varies inversely with the expected rate of growth. That is, higher dividend yields are associated with lower growth rates and vice versa. Therefore, he concluded that the measure of growth that best explains variation in dividend yields among shares is the superior measure of investors' expected growth.

The work of other analysts has challenged Dr. Gordon's conclusion as to the superiority of sustainable growth. In an article entitled, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return" published in Financial Management, Spring 1986, Robert S. Harris reported tests of equity risk premia developed using I/B/E/S forecasts as sources of the growth expectation in the DCF model. He concluded that "Notions of shareholder required rates of return...are based in theory on investors' expectations about the future. Research has demonstrated the usefulness of financial analysts' forecasts for such expectations."

Subsequent to his previously referenced book, Dr. Gordon has done more research. Specifically, with two co-authors, David A. Gordon and Lawrence I. Gould, he published an article, "Choice Among Methods of Estimating Share Yield" (Journal of Portfolio Management, Spring 1989, pages 50-55). In this article, the authors compared the accuracy of four sources of growth rates in estimating the expected return using samples of 75 large electric and gas utilities and 244 firms in total (the 75 electric and gas utilities and 169 industrial firms). The four sources of growth compared were historical earnings, historical dividends, I/B/E/S growth forecasts and the sustainable growth method. The I/B/E/S growth forecast proved to be the most accurate.

More recently, Dr. Gordon appears to have expressed reservations about the usefulness of his model using sustainable growth as the growth component of the DCF model. In a paper delivered to the Institute for Quantitative Research and Finance in March 1990, he said, "The most serious limitation of the Gordon model is the assumption that the dividend expectations can be represented with just two parameters, D and b x r. The financial statement data for b x r can result in a value for g that cannot be accepted as an average for the indefinite future." In this paper, he proposed a new formula to explain the price of stock that relies on growth estimates prepared by security analysts making no mention of sustainable growth (b x r). He also said, "values for earnings and growth based on a consensus of security analysts estimated will do an excellent job in explaining the variation in price among stocks...there is no doubt that the new model will be useful in conjunction with the private estimates of earnings, growth and other independent variables. Such private estimates have been and will continue to be developed by security analysts."

Q. **Is it correct to say that in the past, the Federal Energy Regulatory Commission (FERC) published a DCF-derived generic rate of return on common equity for electric companies?**

A. Yes. However, in July 1991 the FERC voted 5-0 to discontinue the publication of the Quarterly Index Update generic rate of return on common equity for electric utilities. The Quarterly Index was intended to be advisory-only. I am not aware of any single Order issued by the FERC in which the common equity cost rate finding was solely based on the advisory-only, generically-determined, DCF-derived common equity cost rate. During the period of time the advisory-only, DCF-derived, generically-determined return on equity was still published, the FERC considered methodologies other than DCF to arrive at a common equity cost rate.

Q. **Have some FERC Staff witnesses recently relied exclusively upon DCF to estimate the cost of common equity?**

A. No. As recognized by FERC Staff witness, Mr. David Lengenfelder, the DCF model is producing unreasonably low cost of equity estimates, as stated in his testimony in Consumers Power Company (Docket No.s ER92-331-000 and ER92-332-000). Mr. Lengenfelder indicated that "in recent years the resulting DCF-derived cost of equity estimates have exhibited wide variation and in some instances have failed fundamental tests of logic. The DCF-derived cost of equity has been below, equal to, or slightly above the company's cost of debt." (Page 15 of Mr. Lengenfelder's October 19, 1992 testimony). Likewise, in Boston Edison Company (Docket Nos. EL93-150-000 and EL93-10-000), the initial decision (page 42) indicates that FERC Staff witness, Mr. Nicholas P. Lewnes, found "that the constant growth model has produced aberrant results ... produced wide variations in results and in some cases failed fundamental tests of financial logic."

Q. **Given the criticism you have noted of the DCF model, why have you used the model in this proceeding in forming your opinion regarding the proper opportunity cost rate for common equity capital for PECO?**

A. I believe a properly performed DCF analysis can provide useful insight in forming a judgment. However, due to the many infirmities previously discussed and due to, in the final analysis, the myriad of subjective judgments that need to be employed and due to the cold, hard fact that investor behavior is at odds with many of the required assumptions of the model, I advocate the use of a variety of methods and techniques to, in the final analysis, form the judgment with respect to what is the proper opportunity cost rate for common equity capital.

Q. **Is it your testimony that methods other than DCF, such as CAPM, risk premium, and comparable earnings do not require the exercise of subjective judgment and do not proceed from required assumptions that may be completely valid?**

A. No. Every method or model requires the exercise of subjective judgment and no method or model proceeds from assumptions which may be completely valid. Accordingly, I believe the use of a variety of methods is more appropriate than is sole or primary reliance upon DCF.

Q. Has there been regulatory recognition of the deficiencies of DCF in this regard?

A. Yes. For example, Commissions in Indiana and Iowa have spoken on the subject.

The Indiana Utility Regulatory Commission, in a decision dated February 2, 1994[1] recognized the infirmities of the DCF model when it stated:

> The DCF methodology presumes to produce the 'market-required' return on equity, that is, the 'cost of equity' on the market value -- not the book value -- of a company's stock. Unless the market price of a utility's stock equals its book value, the unmodified application of the market-oriented DCF results to a net original cost (book value) rate base understates the earnings necessary to satisfy the investor-required (expected) return. Thus, if the traditional DCF model is strictly applied to an original cost rate base, the investor could earn the cost of capital *only if the investor paid no more* than book value for the stock. If the OUCC's position is that the market price of Indiana utility stocks should be no more than book value, the Commission cannot agree. (emphasis added)

The Iowa Utilities Board[2], in its final decision and Order issued June 17, 1994, also recognized the infirmities of the DCF model when it noted that:

> While the Board has relied in the past on the DCF model, in Iowa Electric Light and Power Company, Docket No. RPU-89-9, "Final Decision and Order" (October 15, 199), the Board stated: '[T]he DCF model may understate the return on equity in some circumstances. This is particularly true when the market is relatively

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[1] Public Utilities Reports - 150 PUR4th, Re: Indiana-American Water Company, Inc., Cause No. 39595, p. 168.

[2] Public Utilities Reports - 152 PUR4th, Re: U.S. West Communications, Inc., Docket No. RPU-93-9, p. 459.

> volatile and the company in question has a market-to-book ratio in excess of one.' Those conditions exist in this case and the Board will not rely on the DCF return. (Consumer Advocate Ex. 367, See Tr. 2208, 2250, 2277, 2283-2284.) The DCF approach underestimates the cost of equity needed to assure capital attraction during this time of market uncertainty and volatility. The Board will, therefore, give preference to the risk premium approach.

In addition, the New York Public Service Commission (NYPSC), approximately every ten years, conducts a generic proceeding regarding, among other issues, the determination of the cost rate for common equity capital for ratemaking purposes. In the proceeding which took place in the 1980's, the NYPSC determined that the DCF methodology was the appropriate methodology to employ. In July 1994, the co-facilitators (Administrative Law Judge and Chief of the Utility Finance Section of the Department of Public Office of Accounting and Finance) of the New York Public Service Commission released a recommended decision resolving Case 91-M-0509, a proceeding to consider financial regulatory policies for New York state utilities. The co-facilitators recommended generic allowed returns based on a weighting of the DCF and CAPM methods. Both facilitators stated in their recommended decision, "a number of experts consulted during the collaborative process contended that the rate of return method upon which the PSC has placed primary reliance, the DCF, is even more volatile than other single methods, and that the DCF tends to produce higher returns when stock prices are below book value and lower returns when stock prices are above book value." (Electric Utility

Week - August 22, 1994, pp. 11-13). It should be noted that the recommendation of the co-facilitators is different from the end result of the collaborative process between the parties which included the Staff of the NYPSC. All parties agreed to the use of a methodology comprised of giving equal weight to at least three different methodologies including DCF, CAPM, risk premium, and comparable earnings.

1. <u>Dividend Yield</u>

Q. How did you compute the dividend yield used in your DCF computation?

A. I developed the dividend yield using closing prices for the three and six months ended February 28, 1997, as well as a spot point in time, namely, March 19, 1997. As can be seen by referring to page 1 of Schedule 15, the current PECO dividend yield of 8.8% is much higher than the dividend yield of 7.7% for the three-month period or 7.4% for the six-month period, respectively. The average of these three yields is 8.0%.

Q. Why did you use various periods of time in developing the dividend yield?

A. Stock prices can be volatile. The current price of stock could be the product of a temporary aberration. In the current market environment regarding PECO, use of a dividend yield for as long as three or six months, together with dividends yields as short as one day, may tend to result in a yield that may be more representative of the future than any one particular period or moment in time. There is no reason to believe that the yield for a particular day or a three- or six-month period is necessarily indicative of the future. Accordingly, I assume the use of several periods of time, or the average of several periods of time, as long as such time period is not too stale, may be more indicative of the future than any one particular period or moment in time, and may minimize the impact of a stock price which is an aberration. Incidentally, had I adopted the average of the PECO dividend yield for the twelve months ended February 28, 1997 of 7.2% with the March 19, 1997 8.8% spot or current yield, to obtain what may be the yield representative of the future, the end result is also an 8.0% PECO dividend yield for DCF purposes. However, it should be noted that the method of taking into account past lower dividend yields for DCF purposes could understate the DCF-derived common equity cost rate that is appropriate for the future, particularly in the PECO circumstance where one of the driving forces of stock price change is investor-anticipated reaction to significantly lower forecasted earnings growth. For example, as I will later explain, Value Line lowered its December 1996 PECO earnings growth rate of 5.5% to 2.5% in mid-March 1997. It should be noted that my use of a PECO dividend yield of 8.0% at a time when the current yield is 8.8%, based on a stock price of $20.50 assumes an implied average future price of $22-1/2 per share. It is quite possible that during the next several months, the average yield derived from giving equal weight to current, three- and six-month average dividend yields will be higher than 8.0%. If that occurs, the PECO DCF-derived cost rate will be higher than the one developed at this time.

Q. **Is there an inter-relationship between the anticipated growth rate and stock price and, hence, dividend yield?**

A. Yes. For example, a similar computation for the average barometer group company indicates a dividend yield of 6.1% compared with the PECO dividend yield of 8.0% before any recognition of the next period dividend, as is required by the DCF model. Not surprisingly, the growth rate for the average barometer group company, as I will later explain, is 4.6% compared with a PECO growth rate of 2.8%. Thus, the sum of the lower dividend yield and the higher growth rate for the average barometer group company is very similar to the higher dividend yield but lower growth rate of PECO, keeping in mind that the investment risk for these two companies is very similar, as I previously stated. Thus, if one reaches back too far in time to develop a dividend yield based on a price that was reflective of a different growth rate than the growth rate of the moment, the end result may be an understated DCF-derived cost rate for common equity capital.

2. DCF Growth Rate

Q. **Please describe growth rates as used in the DCF model.**

A. Returns in the equity market are provided by the receipt of dividends and through capital appreciation of the investment. The expected growth in earnings and dividends per share provides one indication of the DCF growth component. Since the constant growth DCF theory assumes no change over time in either the retention ratio (the complement of the dividend payout ratio) or the price-earnings multiple, the value of a firm's equity is assumed to grow at the same rate as earnings or dividends. However, there is no empirical evidence to support this assumption.

Q. **What published data are available regarding the growth rates of utility earnings?**

A. There are numerous sources of projections of utility earnings growth. One comprehensive source is I/B/E/S, published by Lynch, Jones & Ryan. I/B/E/S publishes an average of all of the available earnings growth rates. It should be noted that I/B/E/S does not include Value Line projections in its tabulation. It should also be noted that I/B/E/S consensus forecasts have been employed by the academic community in regard to DCF studies. S&P also publishes a consensus estimate of earnings but the number of estimates included in the consensus is typically much lower than the number of estimates included in the I/B/E/S consensus.

Another source of data regarding earnings growth which could be considered investor-influencing is Value Line, given its approximate 100,000 subscribers and the fact that the Value Line publication can be found in many public libraries. Because Value Line obviously is a very investor-influencing publication, for the purpose of estimating the growth rate reflected in the price of stock, I have employed I/B/E/S and Value Line projected growth rates in earnings.

Q. **Why do you employ only forecasted growth rates in your DCF calculation at this time?**

A. I believe in the current environment, history is not as representative of the investor's view with regard to a prospective growth rate reflected in stock price as are forecasts, particularly in light of the dynamic changes taking place in the electric industry. It also should be remembered that over the long-term, there cannot be growth in dividends without growth in earnings.

Q. **Is there evidence, other than what you have previously cited, to support your opinion that market analysts influence investor judgment and stock prices?**

A. Yes. In an article in the October 11, 1993 issue of Forbes, David Dremman provides evidence as to the accuracy of analysts' forecasts. He cites examples where the market has moved sharply upon the release of analysts' forecasts. Examples of market reactions to analysts' forecasts are often seen in the daily newspapers. In an article in the February 1993 issue of The Financial Review, Felicia Marston and Robert Harris explain that the commercial viability of services that provide such forecasts and the results of studies of investors' behavior provide evidence that financial analysts' forecasts of corporate earnings are widely used by investors. In addition, Marston and Harris state that "research using consensus forecasts ... demonstrates that such forecasts are incorporated in stock prices." Accordingly, I believe that the use of analysts' forecasts to measure investor expectations is supported by everyday observation as well as by academic research. *It is interesting to note that the previously referenced* Value Line *forecast of mid-*March 1997 of a PECO earnings growth rate of 2.5%, down from the mid-December 1996 forecast of 5.5%, was followed by a PECO common stock price decline of about 10% and a resultant dividend yield increase to 8.8% from 8.0%.

Q. **What PECO growth rate do you adopt for DCF calculation purposes?**

A. I adopted a 2.8% growth rate. In deriving this figure, I observed historical Value Line earnings and dividend growth, Value Line forecasted dividend and earnings per share growth, as well as a retention growth rate derived from Value Line data.

I also observed I/B/E/S projected five-year earnings growth rates. I/B/E/S is a consensus of, in this instance, 18 different forecasts by independent analysts.

As I said earlier, the DCF model is expectational. The proper growth rate to use in the model, therefore, is the expected growth. Accordingly, I chose to take the average of the Value Line forecasted earnings per share growth rate of 2.5% and the consensus forecast by I/B/E/S of 3.1%, which is 2.8%. My use of analysts' forecasts more fully comports with the current views of Dr. Myron Gordon. Information related to the growth rates I employed is shown on Schedule 16.

Q. **What growth rate did you adopt for the barometer group?**

A. I adopted a growth rate of 4.6% using the same methodology I just described with respect to the PECO growth rate of 2.8%.

3. <u>DCF Conclusion</u>

Q. **What is the DCF-derived cost rate for common equity capital for PECO and the barometer group based on the dividend yield and the growth rates you have adopted?**

A. As can be seen by referring to Schedule 17, the sum of the adjusted dividend yield and growth inputs I employed for PECO produce a 10.9% estimated cost rate. For the barometer group, using the identical methodology, the indicated cost rate is 10.8%. I am not surprised that PECO's cost rate is slightly higher than the barometer group, since the barometer group is, in my judgment, slightly less investment risky for reasons I previously cited.

B. Capital Asset Pricing Model

Q. Does modern portfolio theory provide an explanation of the expected rates of return on portfolios of securities?

A. Yes. As developed by the academic community, the Capital Asset Pricing Model (CAPM) attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and instantaneously reflected in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a market premium which is proportional to the non-diversifiable (or systematic) risk of a security. The non-diversifiable risk is obtained by the application of a beta (an indication of the relative risk of a security to the risk of the market) to the market premiums. As I stated earlier, betas are published by, among others, Value Line.

Q. Would you please be more specific as to the theory underlying CAPM?

A. Yes. Under the theory of CAPM, beta is a measure of the risk of a security compared with the risk of the market as a whole. The beta for the market is always equal to 1.00, and therefore companies whose securities have betas greater than 1.00 are considered riskier than the market, while companies with betas less than 1.00 are considered less risky than the market. CAPM is premised on the concept that risk-averse investors demand higher returns for assuming additional risk and, accordingly, higher risk securities are priced to yield higher returns than lower risk securities. Under CAPM theory, there is an incremental reward for bearing additional risk (as measured by beta) above the base risk-free rate which is the return available from investing in U.S. Government Treasury Securities. The specific formula of CAPM is expressed as:

$$K = R_f + B(R_m - R_f)$$

where:

K = required return

R_f = risk-free rate

B = beta

R_m = required return on the market

Q. Should the CAPM model be employed exclusively to gain insight as to the market-required cost rate for common equity?

A. No. As with every model, the CAPM model requires assumptions which may not mirror investor behavior. Further, the R^2's of the betas which must be employed in the CAPM computation are usually low. The R^2 describes the percent of stock price variability that may be attributed to systematic (market) risk. Thus, as is the circumstance of DCF, it is obvious that a CAPM-derived cost rate should not be used exclusively to form a judgment of the investor-required return on common equity. Indeed, a recent study published by the University of Chicago Center for Research and Security Prices and authored by Professor Eugene F. Fama and Kenneth R. French claim that long-term returns depend not on beta, but on company size and price-to-book ratios. Professor Fama is quoted as saying, "Beta as the sole variable explaining returns on stock is dead." However, Professor William F. Sharpe of Stanford University, who won the 1990 Nobel Memorial Prize in Economic Science for theories based on beta has stated that: "I am not willing to make investment decisions based on the theory that there is no relationship between beta properly measured, and expected returns." The point here is that CAPM, like DCF, is certainly not a model which is universally accepted or without flaws.

1. Risk-Free Rate of Return

Q. **What risk-free rate of return have you used in your CAPM calculations?**

A. The risk-free rate of return to be used for long-lived utility assets is a Treasury Bond (T-Bond) yield. The March 7, 1997 30-year T-Bond yield was 6.8%. As I previously mentioned, the consensus forecast of the 30-year T-Bond yield is 6.8% as can be derived from the information shown on page 3 of Schedule 3. I have adopted the 6.8%, which may prove to be conservatively low, as the risk-free rate, particularly in light of recent testimony before the U.S. Congress by Federal Reserve Board Chairman Greenspan indicating the distinct possibility of higher interest rates in the very near term.

Q. **Why would it not be appropriate to use the interest rates on short-term government securities as the risk-free rate?**

A. There are advocates that would argue that the use of T-Bills is the appropriate riskless rate. There is substantial academic support for the use of a long-term relatively riskless rate such as a T-Bond yield as opposed to a much shorter term T-Bill yield in a CAPM computation as the risk-free (also referred to as riskless) rate. Here I have reference to a publication Stocks, Bonds, Bills and Inflation - 1996 Yearbook, authored by Roger Ibbotson. Specifically, Ibbotson has observed in regard to the cost of capital in a regulatory proceeding:

> Most utilities are regulated by local government bodies -- usually a commission appointed to ensure that the utility, because of its alleged monopolistic power, does not take advantage of its customers *and* that the investors in the utility receive a fair rate of return on their invested capital. One of the most important functions of the commission is to determine an appropriate (often called the 'allowed') rate of return. The procedures for setting rates of return for regulated utilities often specify or suggest that the required rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. (pp. 144-145)

There is also other academic support for my position in this regard. For example, Diana R. Harrington (<u>Modern Portfolio Theory and the Capital Asset Pricing Model - A User's Guide</u>, Prentice-Hall, Inc., 1983, page 108) stated, "The longer-term rates did our tests of history better than Treasury Bill rates ... Anyone using the CAPM must choose the R_F proxy with care. The most widely used proxies, 30- or 90-day Treasury Bill rates, are empirically inadequate and theoretically suspect."

2. <u>Market Premium</u>

Q. **Please describe how you developed the market premium used in your CAPM calculation?**

A. The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return (Rm - Rf). One measure of the market premium is the Value Line median forecast of capital appreciation and dividend yield for the 1,700 stocks in the Value Line Survey from which a market premium can be derived. This method, as described in footnote 2 of Schedule 18, page 2 indicates a 5.4% market premium.

Q. Is there another method that can be employed to gain insight with respect to what may be a more appropriate market premium for use in a CAPM computation?

A. Yes. Another method is to rely upon long-term historical data, which have been widely circulated among the investment and academic community over many years. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation (SBBI). From these data, I have calculated a market premium using the common stock arithmetic mean returns less government bond arithmetic mean returns. For the period 1926-1995, the market premium was 7.3% (common stock return of 12.5% - long-term bond return of 5.2%). I should note that an arithmetic mean must be used in the CAPM because it is a single period model. Moreover, as Ibbotson has explained, the importance of using the arithmetic mean in developing the market premium:

> *Arithmetic Versus Geometric Differences*
>
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic means* of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction... (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pp. 153-154)

Q. **What market premium have you adopted?**

A. I have adopted the 6.4% long-term market premium as appropriate at this time. The 6.4% is an average of the 5.4% current estimate of the market premium using Value Line data and the 7.3% Ibbotson historical market premium.

Q. **Can a forecasted market premium be developed based upon a DCF computation?**

A. Yes.

Q. **Why did you not use a forecast of the market premium derived from a DCF computation pertaining to the market as a whole?**

A. As I have already discussed, there is considerable doubt related to the reliability of the DCF model. Further, and more importantly, my intent was to develop an estimate of the common equity cost rate appropriate for rate of return purposes using different methodologies. Had I employed a DCF methodology to estimate the market premium for CAPM computation purposes, the end result would have been the sole use of a single method DCF, rather than two independent methods.

3. CAPM Conclusion

Q. **Have you prepared a summary of your CAPM computation?**

A. Yes. That information is shown on Schedule 18. The CAPM derived PECO common equity cost rate is 12.2% while the average barometer group company CAPM result is not surprisingly slightly lower at 11.8%.

VIII. COMMON EQUITY COST RATE CONCLUSION

Q. **What is the arithmetic average or midpoint of your market-required cost rate for common equity capital based on your DCF and CAPM analysis?**

A. The average of my PECO 12.2% CAPM and 10.9% DCF calculations is 11.6%. For the barometer group, the average of the CAPM and DCF results is 11.3%. The data are summarized on Schedule 2. I believe the PECO and barometer group indicated cost rates for common equity, particularly with respect to PECO, may be conservatively low.

Q. **What is the basis of your opinion in this regard?**

A. The DCF and the CAPM models are interest rate-sensitive. If long-term interest rates rise, it is likely stock prices will fall and dividend yields will increase. The end result of a lower stock price driven by higher interest rates suggests a higher market-required cost of equity. In addition, as I have previously discussed, there is reason to believe the dividend yield I employed in my PECO DCF computation may prove to be understated given the possible mis-match between the possible investor-expected growth rate reflected in the recent past price of PECO stock and the growth rate reflected in the current price of stock. Please remember I took into account dividend yields derived from current, three- and six-month PECO stock prices in order to minimize using stock price which may be an aberration. I urge the Commission to take account of money market changes between now and the time the record in this case is closed.

Q. **Does your recommendation of 11.6% reflect the possible impact of market pressure, selling and issuance expenses relative to the sale of new common stock?**

A. No. I have no direct knowledge of any planned sales of new common stock by PECO.

IX. CHECK ON MARKET-DERIVED COST RATE FOR COMMON EQUITY CAPITAL

Q. **Is there any way you can check the reasonableness of your recommended 11.6% common equity cost rate?**

A. Yes. There are two ways.

Q. **Please explain.**

A. During 1996, state commissions rendered decisions in 22 different rate cases involving electric utilities. The average authorized return on common equity for the group was approximately 11.4% including approximately 11.6% for the fourth quarter of 1996.

Q. **Is there any other method that can be employed to gain insight with respect to what may be the proper opportunity cost rate for common equity capital independent of the use of market models such as DCF or CAPM?**

A. Yes. In order to obtain a specific bond rating, one needs to have the opportunity to experience a specific level of before-income tax interest coverage. That is one of the criteria published by S&P. For electric companies whose long-term debt is rated A, the level of coverage necessary is 4.15 times. For BBB, the standard is 3.15 times. The midpoint of A and BBB is 3.65 times.

As can be seen by referring to Schedule 1, if PECO can achieve an 11.6% return on common equity, its implicit before-income tax interest coverage would be 3.64 times, or almost identical to the derived 3.65 times midpoint published by S&P for an A and BBB bond rating. PECO's long-term debt is rated BBB+.

The last time I checked, the average electric company in the country did maintain an A bond rating. A is one notch above the bottom and two notches from the top of investment grades, and I believe a worthy initial goal for any public utility.

To provide an opportunity of less than the industry average clearly makes a second-class financial citizen out of the utility in question and puts it at a competitive disadvantage in the money market.

X. PAST INVESTOR-EXPERIENCED RETURNS ON COMMON EQUITY AND SHAREHOLDER RECOVERY OF STRANDED INVESTMENT

Q. **Are you aware that shareholder recovery of electric company stranded investment occasioned by deregulation of electric generation has been challenged?**

A. Yes. For example, Peter A. Bradford and Richard K. Silkman co-testified before this Commission in conjunction with PECO's application for issuance of a Qualified Rate Order under Sections 2808 and 2812 of the Public Utility Code regarding the recovery of half its stranded investment that such recovery was improper.

Q. **Do you agree with this view?**

A. No, I do not.

Q. **Is there reason to believe that the risk of stranded investment related to deregulation of electric utility generation was known to investors years ago?**

A. No. Right now, in early 1997, only four states out of fifty have adopted a state-wide industry restructuring plan, namely, California, Massachusetts, Pennsylvania, and Rhode Island. Those plans were adopted within the last year or so. In addition, the Federal Energy Regulatory Commission (FERC) only recently announced its changed policy in this regard. As in the case of California, the FERC stated its intention to permit investor recovery of stranded investment.

Three other states, namely, Michigan, New York, and Vermont have ordered electric utilities to file restructuring plans.

In eight states, namely, Arizona, Connecticut, Illinois, Maine, Minnesota, New Jersey, Texas and Wisconsin, there is a legislative investigation underway that may lead directly to the adoption of restructuring plans.

There are 29 states in which, at the moment, there is an informational fact-finding workshop or study underway where legislation is pending. And, lastly, there are five states in which there is no substantive activity underway or a decision has been made that no action is necessary.

Investors do not reflect elements of risk until there is the imminent prospect of such risk, keeping in mind that in these days in particular, the investment horizon of most common stockholders is but a few years and not ten or fifteen years.

Q. **Why, in your opinion, should investors be permitted to recover stranded investment?**

A. Historically, government created circumstances whereby competition was limited for, among others, electric utilities. This benefit bestowed by government was not a gift to utilities and their investors. Rather, government expected and required electric utilities and their investors to pay a price by accepting opportunity return rates below those available in industries not protected from competition. Moreover, the utility was obligated to provide safe, reliable service all of the time to all customers who sought service, including the well-to-do and the not so well-to-do and including customers residing in sparsely populated rural areas as well as urban areas. Electric utilities and their investors met their end of the bargain by producing safe, reliable service to all who sought service at prices set by regulators which resulted in returns on investment below non-price regulated industries, as I will explain. Thus, if an investment in property was deemed prudent at the time the decision to invest was made, the price of service established by regulators reflected the opportunity to recover the cost of and a fair return on the investment over the life of the asset, when the property financed by investors was placed in service.

Q. **Does the fact that the Pennsylvania legislature has altered its policy toward utility competition cause you to reconsider your views?**

A. No. When government abandons or changes policy from a government-created monopoly circumstance to a competitive environment for electric utilities, I believe investors should be entitled to recover the full cost of investor-financed facilities rendered uneconomic in whole or part as a result of that governmental policy change. To do otherwise is not only unfair, but may be considered confiscation of property. Further, when the magnitude of such stranded investment is significant, as in PECO's circumstance, failure to provide for recovery of and return on stranded investment could lead to bankruptcy and cause irreparable harm to both customers and investors.

Q. **Is there any reason to believe that PECO's shareholders expected to recover their investment?**

A. Yes. This Commission, in 1990, permitted PECO to put into effect a price of service to consumers adequate to provide an opportunity to recover the cost of and earn a fair return on its investments. Clearly, PECO investors until recently had no reason to believe full recovery of and a return on their investment in generating plant was in jeopardy as a result of deregulation. Accordingly, the suggestion that investors have long been aware that serious losses, even bankruptcy, were possible due to fundamental regulatory changes is out-of-keeping with the facts.

Q. **If past utility service rates established by regulators did not recognize the risk of stranded investment loss, is it possible that the earnings experienced by investors nonetheless compensated them for such risks?**

A. No, particularly with respect to PECO, given that its service rates were last established in 1990 or long before an investor could possibly have believed deregulation of the electric utility industry was imminent and stranded investment would not be recovered.

Q. **Are you familiar with a September 13, 1993 study, "Electric and Telephone Utility Stockholder Returns: 1972-1992" performed by Michael Foley, Director of Financial Analysis and Ann Thompson, Policy Analyst, both employees of the National Association of Regulatory Utility Commissioners (the "NARUC" report), which purports to demonstrate that electric utility investors have fared**

comparatively well as compared to their electric utility and/or industrial company *counterparts?*

A. Yes. The stated objective of that study was to provide a ranking of utilities according to their average internal rate of return, average basic rate of return, and average investor wealth rate of return which stockholders recovered and to present a comparison between the shareholders' returns of the utilities and the average investment returns of the Standard & Poor's (S&P) Index of 400 Industrials and the Value Line Industrial Composite of over 900 companies.

Q. **How did the authors measure shareholder returns?**

A. The study is based on three computer generated models which perform over 16,500 shareholder return calculations during the 21-year period, 1972-1992. The first model computed shareholder returns as measured by changes in stock prices and cash dividends paid to common stockholders to calculate the average internal rate of return earned by investors. These results are based on a method of determining returns which assume that dividends are reinvested into the stocks.

The second model did not take into account dividend reinvestment.

The third model determined returns based upon investors' wealth regarding ownership of a particular stock that was very similar to the first model.

The study covered 97 major electric and telephone utilities and utility holding companies and the S&P 400 Industrials, as well as approximately 800 industrials derived from the Value Line Industrial Company Group. The study displayed 18 three-year holding periods, 17 four-year holding periods, 16 five-year holding periods, and one 20-year holding period for a total of 171 distinct hypothetical holding periods.

The authors offer no explanation as to why averaging numerous holding periods during the study period provides appropriate or useful comparative information in their quest to discover whether the implied rate of return based upon market prices of stock and dividends paid indicate whether public utility companies earned the same as, more than, or less than industrial companies. Moreover, the authors are silent on the issue of financial risk differences between the groups. It is a known fact that the average common equity ratio for the average utility is less than is the average common equity ratio for an industrial company, keeping in mind that investment risk is the sum of both business and financial risk. Thus, if the business risk of utilities is presumed by investors to be less than non-utility companies such as industrials, the market permits the employment of more debt and less equity or more financial leverage to the point where the investment risk for each is similar. For example, if one compares bond yields for industrial companies and utility companies rated AAA, AA, A, and BBB, one finds the yield difference between the two to be a matter of a minor amount of basis points.

Stated another way, the cost rate to attract capital to each is similar, undoubtedly reflective of the presumed lower business risk of a utility with the higher financial risk of a utility offsetting, the higher business risk and lower financial risk of the non-regulated industrial company.

Q. **What did the authors claim were the key findings of their study?**

A. The authors claim the key findings of their study are:

> the common stockholders of 72% of all major electric and telecommunication utility companies earned a higher internal rate of return on investment than did the average stockholder of the major non-utility U.S. industrial corporations over the 21-year period 1972-1992; 45% higher based on the second method; and 73% higher based upon a third method.

However, and as I noted previously, these cited statistics are the product of averaging holding periods and are not the product of the average stockholder returns for the study period.

Q. **What did the authors claim the study confirms?**

A. The authors claimed the study confirms that the often repeated arguments of utility sympathizers regarding the "inadequacy" of earnings and the inability of utilities to attract investment capital are unfounded and without merit.

Q. **Do you believe the results of this study confirm that utility investors have been**

compensated for the risk of electric utility stranded investment?

A. No. The first method employed in this study to determine the internal rate of return was to add dividends paid to the appreciation in the market value of stock between two points in time. The difference or gain reflected in the market value of stock between two different moments in time are not dollars paid by consumers reflected in the regulatory authorized price of service charged consumers during the same period in time.

In addition, there is no evidence presented that the internal rates of return developed in the study are anything more than the accident of the history of investing. Such implied rates of return were neither necessarily investor-expected nor investor-required.

Q. **If the NARUC Report were updated, would the conclusion be the same as claimed by the authors of the study?**

A. No. I have updated the study with regard to the first method employed for the period 1972 through 1996. I have also performed calculations for the period 1992-1996 and 1992 through February 1997 to determine if the conclusion would be the same. The period of time since 1992 is likely the period when investors perceived the possibility of loss due to stranded investment occasioned by electric utility deregulation. The method I employed to perform the updated implied total return calculation was identical to the method employed by Mr. Foley in his original study. A summary of the results of the update are shown on Schedule 19.

Q. **Would you please describe the results of your update of the NARUC study?**

A. The NARUC study reported that the percent of all electric and telephone utilities whose implied total overall return was greater than the industrial companies was 72% based on averaging 171 different holding periods. If a single holding period had been utilized by NARUC, this figure would have dropped to 43%.

When the single holding period figure is updated through 1996, the 43% number falls to 33%. Moreover, for the period 1992 through 1997 (through February) only 8% of utilities experienced an implied overall market return greater than the major non-regulated industrial companies.

Q. **How did PECO fare?**

A. Utilizing the NARUC report's 1972-1992 study period, PECO's investor return was 8.31% or lower than the 9.79% average of all telephones and electrics, electrics only at 9.56%, telephones only at 12.41%, and 10.18% for industrials. For the updated 1972-1996 and 1992-1997 periods, again, PECO fared worse than all other groups.

Q. **What do you conclude regarding the update of the 1992 NARUC study?**

A. Based upon a single period calculation, PECO earned less, not more, than the industrial companies, and less than the average of all utilities, electrics or telephone utilities. Further, if the implied total stockholder rate of return is to be used as the standard to determine if utility investors fared better or worse than non-utility industrial firms over the past twenty-five years, the conclusion one must reach is that utility investors have not kept pace.

A. Alternative Method to Determine Whether Electric Utilities Earned More than Non-Utility <u>Investors from Cash Paid by Consumers</u>

Q. **Is there a more appropriate method than that used in the NARUC study to determine if electric utility investors have experienced a higher return compared to non-utility industrial companies?**

A. Yes.

Q. **Please explain.**

A. Electric utility regulatory-determined service rates charged customers include a provision for an opportunity return to be paid investors for the recovery of and a return on investor-provided facilities. Normally, a uniform computation of the rate of return earned on a similar measure of value, common equity measured at book cost, would indicate if electric utilities earned more than non-utility industrials. However, since utility accounting permits the capitalization of the cost of capital used to finance plant under construction (allowance for funds used during construction (AFUDC)) but typical non-utility accounting does not, a comparative computation must recognize such difference. Utility service rates do not reflect the cash necessary to pay for AFUDC. It is strictly a bookkeeping entry. The offset of such costs are capitalized as an asset and included in the plant account. When the plant under construction is placed in service and when the regulatory commission authorizes service rates charged consumers to reflect a return on and recovery of the plant, then and only then do customers pay cash in service rates for the use of such property over the very long life of the property.

Accordingly, for comparison purposes, the proper computation is the rate of return on the book value of common equity (utility net income available to common equity less AFUDC, a non-cash item not paid by consumers), relative to average common equity compared to the rate of return on book common equity experienced by non-utility industrial companies for the same period of time.

Q. **Have you performed such calculations?**

A. Yes. I reviewed data for the same companies that were included in the NARUC study for the period 1972-1992 and an updated period 1992 - 1995. The update had to end in 1995 because 1996 earnings data for most of the companies included in the study are not yet available. The results of my study are shown on Schedule 20.

Q. **What do your calculations reveal?**

A. The 1972 - 1992 average cash rate of return experienced by PECO was 4.25% compared to 9.03% for all utilities, 8.74% for the electrics, 12.96% for the telephone companies, and 14.33% for the industrial index. The corresponding figures for the updated period 1972 - 1995 are 5.12% for PECO, 9.25% for all utilities, 8.97% for the electrics, 13.05% for the telephones, and 15.10% for the industrial index. For the period 1992 - 1995, PECO's cash return was 10.95%, compared with 10.76% for all utilities, 10.55% for the electrics, 13.83% for the telephones, and 18.65% for the industrial index.

Q. **What do you conclude from the alternative analysis?**

A. There is no basis for asserting that electric utility investors, most particularly PECO investors, were compensated for the risk of stranded investment during the period 1972 - 1992. In addition, since 1992 the industrial index earned significantly more than all of the utilities studied.

B. PECO Shortfall in Cash Earnings on Common Equity 1972-1995

Q. **Have PECO investors enjoyed an achieved return on common equity during the years 1972-96, inclusive, equal to the regulatory intended return?**

A. No.

Q. **What is the basis of your opinion?**

A. I have prepared a tabulation of the PECO income available for common equity, including and excluding AFUDC, actually reported for the years 1972 through 1996 and the intended return for the same period. The PECO intended return is the product of multiplying the electric division intended rate of return for each year as established by the PUC times the average book value of common equity for each year. I am aware that during part of the time, PECO operated a steam division and all during the time a gas division whose authorized rate of return on common equity were not identical, but similar to the electric division. Since PECO's electric division constitutes about 90% of total operations, I believe the end result of my tabulation is very instructive.

As can be seen by referring to Schedule 21, the period reported net income available to common equity was about $7.6 billion, but when AFUDC is removed, the income is but $4.3 billion, or a difference of $3.3 million of AFUDC income, a bookkeeping entry and non-cash. The regulatory intended period return was about $9.1 billion, or $1.5 billion more than the $7.6 billion achieved return. Thus, when the sum of the $1.5 billion actual return compared with the intended return is added to the $3.3 non-cash derived bookkeeping return not recovered from customers, the aggregate shortfall is about $4.8 billion, all related to utility plant provided by investors. AFUDC is, in effect, a promise of recovery from customers over the life of the plant and if there is no recovery of stranded investment related to plant, not only did investors not recover from customers' AFUDC, but also did not earn whatever was intended by regulators.

It should be noted that PECO does not seek any recovery of the $1.5 billion difference between the $7.6 billion achieved return and the $9.1 billion regulatory intended return simply because neither PECO, nor any other utility, is entitled to a guaranteed return, but instead only an opportunity return. Under such circumstances, it is quite clear, up until the time of deregulation, the risk rate regarding stranded investment was anything other than a risk-free rate, such as a T-Bond.

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

A. Yes.

Appendix A

to the

Direct Testimony

of

Joseph F. Brennan, Chairman of the Board
AUS Consultants - Utility Services

Education, Business and Regulatory
Experience of Joseph F. Brennan

Education

I am a graduate of Temple University of Philadelphia, where I received a Bachelor of Science Degree from the School of Business Administration in 1960. The principal subjects leading to this degree included finance, economics, accounting, and related courses.

Non-Utility Employment

In 1950, I was employed by the Gulf Oil Corporation's Philadelphia Office and was assigned to its Financial Accounting Department, where I remained until late 1952. From late 1952 until late 1954, I served in the U. S. Army. Upon completion of my military service, I returned to the Financial Accounting Department of Gulf Oil Corporation and remained in its employ until 1956.

Utility Employment

In 1956, I was employed by the service company subsidiary of a water utility holding company, which owned approximately 90 operating utility companies throughout the United States. The name of the company was American Water Works Service Company. Initially, I was assigned to its Treasury Department. In early 1961, I was elected Assistant Treasurer. In the middle of 1966, I was elected Treasurer of many of the holding company's operating subsidiaries. During my employment, I also was Assistant Division Manager of Pittsburgh Division, headquartered in Mt. Lebanon, Pennsylvania.

During my employment with affiliates of the holding company, I had responsibility for forecasting the cash requirements and income expectations of many of its operating subsidiaries. I also negotiated lines of credit with banks for operating subsidiaries.

I was responsible for continuous studies of the ability of the operating subsidiaries to permanently finance their temporary borrowings or to refinance or refund outstanding permanent-type securities. I designed and recommended permanent financing programs for these companies. On their behalf, I negotiated sales of securities with institutional investors, such as insurance companies and pension funds, either personally or through investment bankers. I also prepared or assisted in the preparation of fair rate of return testimony and other financial data presented in regulatory commission proceedings. During my tenure as Treasurer of some of the operating companies, I was responsible for accounting exhibits and accompanying tariffs filed in the rate proceedings in several states in which the subsidiaries did business. My responsibilities also included the filing of annual reports with commissions.

Consulting Work - Nature of Work

I am Chairman of the Board of AUS Consultants, Mt. Laurel, New Jersey. In late 1967, I founded Associated Utility Services, Inc., the predecessor to AUS Consultants. AUS Consultants (AUS) is an independent firm comprised of several different groups employing more than 200 full- and part-time people (utility ratemaking, valuation, market research, industry analysis, and C. A. Turner publications). The Utility Services Group specializes in every aspect of ratemaking, ranging from rate of return, depreciation, cost of service, tariff design, lead/lag studies, and ratemaking accounting. Services have been performed for natural gas, electric, telephone, water, wastewater, cable television, maritime shipping, products pipeline, railroad, bus transportation, steam heating, and other enterprises whose price of service is established by a governmental or regulatory body. The Valuation Services Group values companies and assets (tangible and intangible), including the value of intelligence transfer and property in ad valorem tax cases. Valuation services are usually rendered primarily in conjunction with mergers, acquisitions, and leveraged buy-outs, in the non-regulated environment. The Market Research Group performs consumer market research, customer satisfaction surveys (for AT&T), surveys related to demand-side management, political pollings (ABC/Washington News Post), custom research for financial institutions (Merrill Lynch) and many Fortune 500 companies. The Industry Analysis Group provides a full range of demand-side management services for electric, gas and water utilities, energy market strategy, and economic analyses of the auto industry and agricultural industries, as well as studies regarding market share and market dominance in both a regulated and unregulated environment. C. A. Turner Utility Reports provides utility financial data and derived ratios monthly and annually to about 1,000 subscribers which include utilities, regulators, individuals, brokerage firms, lawyers, and libraries.

Expert Testimony Offered Before Regulatory Bodies

I have offered testimony with respect to the subject of fair rate of return or utility financial matters before state regulatory bodies in Alabama, Arkansas, California, Connecticut, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Vermont, Virginia, Washington, and West Virginia. I have offered testimony before the Public Service Commission of the District of Columbia; Metropolitan Dade County (Miami), Florida; the Public Service Commission of the Commonwealth of Puerto Rico; the Virgin Islands; the Federal Communications Commission; the Federal Energy Regulatory Commission and its predecessor, the Federal Power Commission; the Federal Maritime Commission; the Interstate Commerce Commission; the Securities and Exchange Commission; and the Canadian Radio and Television Commission. I have also offered testimony in Arkansas, California, Colorado, Connecticut, Florida, Oklahoma, Pennsylvania, Texas, and West Virginia, before city and town agencies involved in setting cable television rates and charges.

Employment by Regulatory Agencies or Municipalities and Other Engagements

As a consultant employed by the Delaware Public Service Commission, I have testified in several Delmarva Power & Light Company rate cases, two Diamond State Telephone Company cases, and several other cases. Diamond State was a wholly-owned subsidiary of American Telephone & Telegraph Company. I have also testified on behalf of the Arizona Corporation Commission in connection with rate cases filed by Mountain

States Telephone & Telegraph Company, another Bell System unit. I have testified on behalf of the Commonwealth of Puerto Rico as a rate of return witness before the Federal Maritime Commission involving North Atlantic shipping rates, and I have testified before that Commission on behalf of the Virgin Islands in a similar matter. In addition, I offered testimony before the Securities and Exchange Commission involving the divestiture of the gas properties of Delmarva Power & Light Company under the Public Utility Holding Company Act of 1935, on behalf of the Delaware Public Service Commission. My testimony was also submitted before the FPC on behalf of the Delaware Public Service Commission involving the rate of return to employ in a power supply agreement involving a multi-state electric operation and in a case involving wholesale power rates.

I have also been employed by the Cities of Rochester, New York, and Baltimore, Maryland, involving bus transportation. I have also been employed by Washington Metro and the United States Department of Justice concerning the valuation of D.C. Transit.

I was part of a team of persons to make a study of the cost of service and a load management plan for the Environmental Planning Agency of the State of Hawaii involving Hawaiian Electric Company.

I offered testimony in regard to class rate of return differential to be reflected in the cost of service by customer class. I have also co-authored a study on this subject on behalf of the Delaware Public Service Commission which was funded by the Department of Energy, I have testified on this subject on behalf of investor-owned electric companies in Arkansas and Texas, and on behalf of the City of New Orleans.

I have also offered testimony before the Regulatory Control Authority of

Connecticut regarding new factors for cost of service studies and tariff design, and I have offered testimony before this body as to a methodology to employ in connection with the regulation of cable television and the overall rate of return requirement.

I have also testified before court-appointed appraisers in dissenting stockholder suits involving the valuation of common stock for a closely held utility.

I have also performed studies regarding the proper price of water and wastewater on behalf of Baltimore County, Maryland and Bucks County, Pennsylvania involving disputes with the cities of Baltimore, Maryland and Philadelphia, Pennsylvania, respectively.

Partial List of Clients Served

ELECTRIC

Appalachian Power Company
Arkansas Power and Light Company
Atlantic City Electric Company
Canal Electric Company
Carolina Power & Light Company
Columbus Southern Power Company
Conowingo Power Company
Consumers Power Company
Delmarva Power & Light Company
Duquesne Light Company
Fitchburg Gas & Electric Light Co.
Hawaiian Electric Company
Indiana Michigan Power Company
Iowa-Illinois Gas & Electric Company
Kentucky Power Company
Lockhart Power Company
Metropolitan Edison Company
Michigan Power Company
Monongahela Power Company
Nantahala Power & Light Company
Ohio Edison Company
Ohio Power Company
Ohio Valley Electric Company
Orange and Rockland Utilities, Inc.
PECO Energy Company
Pennsylvania Electric Company
Pennsylvania Power & Light Company
Pennsylvania Power Company
The Potomac Edison Company
Potomac Electric Power Company
Tampa Electric Company
The Washington Water Power Company
West Penn Power Company
Western Massachusetts Electric

NATURAL GAS DISTRIBUTION AND PIPELINE

Algonquin Gas Transmission Company
American Natural Gas Company
Bay State Gas Company
Buckeye Pipe Line Company
Carolina Pipeline Corporation
Citizens Gas & Coke Utility
Columbia Gas of Maryland
Columbia Gas of Pennsylvania
Columbia Gas of West Virginia
Consolidated Gas Transmission Corp.
Delmarva Power & Light Company
East Ohio Gas Company
Elizabethtown Gas Company
Equitable Gas Company
Great Lakes Gas Transmission Co.
Honolulu Gas Company
Hope Gas, Inc.
Hope Natural Gas Company
Indiana Gas Company
Kentucky-West Virginia Gas Company
Lone Star Gas Company
Michigan Power Company (Gas Div.)
National Fuel Gas Distribution Corp.
New Jersey Natural Gas Company
North Penn Gas Company
Northern Utilities, Inc.
Oklahoma Natural Gas Company
Panhandle Eastern Pipeline Company
Pennsylvania Gas Association
Pennsylvania Gas & Water Company
Peoples Natural Gas Company
Philadelphia Electric Co. (Gas Div.)
T.W. Phillips Gas & Oil Company
Providence Gas Company
Public Service Co. of N. Carolina, Inc.
The Southern Connecticut Gas Company
Texas Eastern Transmission Corp.
Transwestern Pipeline Company
UGI Corporation
Virginia Electric & Power Co. (Gas Div.)
West Ohio Gas Company

WATER & SEWER

American Water Works Company
(over 30 subsidiaries)
Artesian Water Company
Atlantic City Sewerage Company
Barnstable Water Company
Bridgeport Hydraulic Company
Citizens Utilities Company
Commonwealth Water Company
Edgartown Water Company
Elizabethtown Water Company
Florida Water & Utilities Company
Hackensack Water Company
Indian Rock Water Company
Kaanapali Water & Sewer Co.
Long Island Water Corporation

Middlesex Water Company
Monmouth Consolidated Water Company
New Haven Water Company
Newtown Artesian Water Company
Pennichuck Water Works
Pennsylvania Gas & Water Company
Philadelphia Suburban Water Company
Roaring Creek Water Company
St. Louis County Water Company
Seymour Water Company
Spring Valley Water Company
Utilities and Industries Corporation
Washington Water Power Company
Western Pennsylvania Water Company
York Water Company

TELEPHONE

Bell Atlantic Corporation
Bell of Pennsylvania
Diamond State Telephone Company
Chesapeake & Potomac Telephone Co.
Commonwealth Telephone Company
Eastern Illinois Telephone Corp.
Illinois Consolidated Telephone Co.
Norfolk & Carolina Telephone Company
Puerto Rico Telephone Company
Quincy Telephone Company

Rochester Telephone Corporation
Virgin Islands Telephone Company
And over 50 operating subsidiaries of:
ALLTEL Corporation
Central Telephone Company
Continental Telecom, Inc.
GTE Corporation
United Telephone System, Inc.
Vista-United Telecommunications

CATV

American Television Communication Corporation
Bakersfield Cable Television
Cable Owners Association - California, Connecticut, New England, Pennsylvania, Rocky Mountain, Vermont
Cablecom-General, Inc.
Canadian Cable Television

COMCAST Cable Communications, Inc.
Kern County Cable Television
LVO Cable, Inc.
National Cable Television Association
National Cable Television Owners Association
San Juan Cablevision
Warner Cable Corporation

REGULATORY AND GOVERNMENTAL

Cities of Rochester, New York and Baltimore, Maryland--Transit	Delaware Public Service Commission re: all regulated utilities
City of Anchorage, Alaska	The Delaware River Bridge Commission
City of New Orleans, LA	State of Hawaii Department of Planning and Economic Development
Arizona Corporation Commission	Internal Revenue Service Commission
Baltimore County, Maryland	Medford Township, NJ
Bucks County, Pennsylvania	U.S. Department of Justice--Washington Metro (D.C. Transit)
City of Philadelphia Gas Works	The U.S. Virgin Islands
Collier County, Florida	
Commonwealth of Puerto Rico	

Memberships, Publications and Appearances

Memberships have included the Board of Directors of the Society of Utility and Regulatory Financial Analysts (SURFA) (formerly National Society of Rate of Return Analysts), the American Gas Association, the Pennsylvania Gas Association, the United States Telephone Association, the National Association of Water Companies, the National Cable Television Association and the New England Gas Association.

I have been a member of the National Water Company Conference's Committee on Accounts and Corporate Finance, and I have been a guest editorialist for the Conference's Quarterly Review on several occasions. On three other occasions, I appeared before the Conference's Annual Convention. In 1967, I prepared an article which appeared in the March-April issue of The Financial Analysts Journal. I have also co-authored articles which appeared in the April 26, 1973 and January 21, 1988 issues of Public Utilities Fortnightly, and authored articles which appeared in the April 10, 1980 and February 18, 1982 issues of that publication.

In May 1970, 1979, and 1984, I appeared before the Iowa State University Conference on Public Utility Valuation and the Rate Making Process at Ames, Iowa. I also addressed the Mid-America Regulatory Conference at Iowa State University at Des Moines in 1983. In addition, I appeared before two different Annual Conventions of the National Cable Television Association to discuss rate regulation of cable television. I have also appeared in a similar capacity before regional cable television conventions in Dallas, Texas; Augusta, Maine; New York, New York; Philadelphia, Pennsylvania; Lancaster, Pennsylvania; and San Diego, California. In 1973 and 1974, I was invited to appear at NARUC-sponsored seminars at the University of South Florida in St. Petersburg. My assigned subject was "Fair Rate of Return". During 1975, I appeared before the New Jersey Utilities Association and addressed the Annual Meeting of the New York Independent Telephone Association at Cornell University. I addressed an American Bar Association Seminar in Washington, D.C. or San Francisco, California, on the subject of cost of money in 1977, 1982, 1985, 1986 and 1987. I presented a paper to the NARUC Annual Convention in New Orleans on the subject of utility ratemaking. I also presented a paper in 1978 at The Greenbrier before the Great Lakes Section of NARUC. In May 1979, I presented a paper in Columbus, Ohio, before the 2nd Annual Convention of the National Association of Regulatory Attorneys. I also made a presentation before a seminar conducted by the New Mexico State University in October 1979 and in May 1982. In April 1983, I delivered a speech concerning "Organizations in Transition: Telecommunications" at a forum sponsored by Arizona State University's College of Business Administration Alumni Association. I have presented prepared remarks before the American Gas Association's Finance and Rate Committees at Seminars in 1982, 1984, 1987 and 1989. I made a presentation at a seminar regarding cost of capital co-sponsored by Temple University in Atlantic City, NJ, in 1983. I presented remarks at the Edison Electric Institute's 1984 Financial Forum in Phoenix, Arizona. I delivered a speech in Washington, D.C., for the Utilities Law Institute in June, 1986, entitled "Differences in Regulation in a Lower Inflation, Lower Tax Rate, Low Growth Environment: Rate Decrease Proceedings, Vanishing Rate Base, Rate of Return Issues." In May 1989, I presented a speech entitled, "The Capital Structure: Regulatory vs. Real" at the annual SURFA convention in Washington, DC. In June 1989, I presented a speech on ratemaking matters before the Indiana CPA Society. In June 1990, I presented a speech entitled "A Financial Profile of New Jersey Investor-Owned Water Companies" at the meeting of the New Jersey Chapter of the National Association of Water Companies. In February 1992, I presented a speech before the Great Lakes Section of NARUC. In 1995, I presented a paper before the American Bar Association Regulatory Group in Washington, DC regarding implications of deregulation of energy and telecommunications utilities.

PECO EXHIBIT JFBr-1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

EXHIBIT

TO ACCOMPANY THE

DIRECT TESTIMONY

OF

JOSEPH F. BRENNAN

Regarding the Development of
the Cost Rate for Common Equity,
Overall Rate of Return
and an Overall After-Tax Discount Rate
Employed to Compute Stranded Investment

PECO Energy Company
Table of Contents
to the Financial Supporting Exhibit
of Joseph F. Brennan

PECO Energy Company
Table of Contents
to the Financial Supporting Exhibit
of Joseph F. Brennan

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

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

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

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

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

* Including debt due within one year.

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

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

(4) As developed on Schedule 2.

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

PECO Energy Company
Summary of Common Equity Cost Rate Recommendation

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

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

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

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

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

Moody's
Comparison of Interest Rates for Investment Grade Long-Term Debt for Investor-Owned Public Utility and Industrial Companies for 1955, the Ten Years Ending 1996 and 1997 to date

	Aaa Rated			Aa Rated			A Rated			Baa Rated		
Years	Public Utilities	Industrials	Spread	Public Utilities	Industrials	Spread	Public Utilities	Industrials	Spread	Public Utilities	Industrials	Spread
1955	3.09 %	3.00 %	0.09 %	3.13 %	3.11 %	0.02 %	3.22 %	3.16 %	0.06 %	3.43 %	3.47 %	(0.04)%
1987	9.52	9.22	0.30	9.77	9.59	0.18	10.10	9.88	0.22	10.53	10.62	(0.09)
1988	10.05	9.36	0.69	10.26	9.62	0.64	10.49	9.99	0.50	11.00	10.66	0.34
1989	9.32	9.19	0.13	9.56	9.36	0.20	9.77	9.71	0.06	9.98	10.38	(0.40)
1990	9.45	9.19	0.26	9.65	9.45	0.20	9.86	9.77	0.09	10.06	10.64	(0.58)
1991	8.85	8.69	0.16	9.09	9.00	0.09	9.36	9.25	0.11	9.55	10.05	(0.50)
1992	8.19	8.09	0.10	8.55	8.37	0.18	8.69	8.53	0.16	8.86	9.08	(0.22)
1993	7.29	7.14	0.15	7.44	7.37	0.07	7.59	7.57	0.02	7.91	7.95	(0.04)
1994	8.06	7.86	0.20	8.21	8.09	0.12	8.30	8.25	0.05	8.63	8.62	0.01
Avg.	8.84 %	8.59 %	0.25 %	9.07 %	8.86 %	0.21 %	9.27 %	9.12 %	0.15 %	9.57 %	9.75 %	(0.19)%
Jan.1995	8.50 %	8.38 %	0.12 %	8.66 %	8.53 %	0.13 %	8.73 %	8.67 %	0.06 %	9.15 %	9.01 %	0.14 %
Feb.1995	8.33	8.19	0.14	8.45	8.32	0.13	8.52	8.44	0.08	8.93	8.77	0.16
Mar.1995	8.18	8.06	0.12	8.29	8.18	0.11	8.37	8.29	0.08	8.78	8.62	0.16
Apr.1995	8.08	7.98	0.10	8.17	8.06	0.11	8.27	8.19	0.08	8.67	8.52	0.15
May 1995	7.71	7.58	0.13	7.80	7.68	0.12	7.91	7.80	0.11	8.30	8.10	0.20
Jun.1995	7.39	7.21	0.18	7.49	7.36	0.13	7.60	7.46	0.14	8.01	7.79	0.22
Jul.1995	7.51	7.31	0.20	7.60	7.48	0.12	7.70	7.60	0.10	8.11	7.97	0.14
Aug.1995	7.66	7.47	0.19	7.71	7.65	0.06	7.83	7.75	0.08	8.24	8.15	0.09
Sep.1995	7.42	7.21	0.21	7.48	7.41	0.07	7.62	7.50	0.12	7.98	7.88	0.10
Oct.1995	7.23	7.02	0.21	7.30	7.24	0.06	7.46	7.32	0.14	7.82	7.68	0.14
Nov.1995	7.13	6.90	0.23	7.22	7.13	0.09	7.43	7.20	0.23	7.81	7.55	0.26
Dec.1995	6.94	6.70	0.24	7.03	6.95	0.08	7.23	7.02	0.21	7.63	7.35	0.28
Avg.	7.67 %	7.50 %	0.17 %	7.77 %	7.67 %	0.10 %	7.89 %	7.77 %	0.12 %	8.29 %	8.12 %	0.17 %
Jan.1996	6.92 %	6.69 %	0.23 %	7.02 %	6.95 %	0.07 %	7.22 %	7.03 %	0.19 %	7.64 %	7.29 %	0.35 %
Feb.1996	7.11	6.86	0.25	7.20	7.12	0.08	7.37	7.24	0.13	7.78	7.47	0.31
Mar.1996	7.45	7.25	0.20	7.55	7.49	0.06	7.73	7.63	0.10	8.15	7.91	0.24
Apr.1996	7.60	7.40	0.20	7.70	7.65	0.05	7.89	7.76	0.13	8.32	8.06	0.26
May 1996	7.73	7.52	0.21	7.79	7.75	0.04	7.98	7.90	0.08	8.45	8.14	0.31
Jun.1996	7.83	7.59	0.24	7.87	7.86	0.01	8.06	7.98	0.08	8.51	8.28	0.23
Jul.1996	7.78	7.51	0.27	7.83	7.81	0.02	8.02	7.91	0.11	8.44	8.23	0.21
Aug.1996	7.59	7.33	0.26	7.66	7.63	0.03	7.84	7.69	0.15	8.25	8.09	0.16
Sep.1996	7.76	7.55	0.21	7.84	7.80	0.04	8.01	7.89	0.12	8.41	8.28	0.13
Oct.1996	7.50	7.28	0.22	7.60	7.55	0.05	7.77	7.62	0.15	8.15	7.98	0.17
Nov.1996	7.21	6.99	0.22	7.32	7.29	0.03	7.49	7.34	0.15	7.87	7.70	0.17
Dec.1996	7.33	7.07	0.26	7.44	7.38	0.06	7.59	7.43	0.16	7.98	7.80	0.18
Avg.	7.48 %	7.25 %	0.23 %	7.57 %	7.52 %	0.04 %	7.75 %	7.62 %	0.13 %	8.16 %	7.94 %	0.23 %
Jan. 1997	7.53 %	7.30 %	0.23 %	7.68 %	7.58 %	0.10 %	7.77 %	7.64 %	0.13 %	8.18 %	8.00 %	0.18 %
Feb. 1997	7.47	7.14	0.33	7.60	7.47	0.13	7.64	7.52	0.12	8.02	7.86	0.16
Mar. 1997 (2)	7.75	7.44	0.31	7.88	7.74	0.14	7.91	7.80	0.11	8.30	8.13	0.17
Avg.	7.58 %	7.29 %	0.29 %	7.72 %	7.60 %	0.12 %	7.77 %	7.65 %	0.12 %	8.17 %	8.00 %	0.17 %

Notes: (1) All Yields are distributed yields.
(2) Closing yields on March 13, 1997.

Source of Information: Moody's Investors Service

Exhibit JFBr-1
Schedule 3
Page 1 of 3

Moody's
Comparison of Interest Rates for Investment Grade Long-Term Debt for Investor-Owned Public Utility and Industrial Companies for 1955, the Ten Years Ending 1996 and 1997 to date

	Yield Spread Aa vs. Aaa		Yield Spread A vs. Aa		Yield Spread Baa vs. A	
	Public Utility	Industrial	Public Utility	Industrial	Public Utility	Industrial
1955	0.04 %	0.11 %	0.09 %	0.05 %	0.21 %	0.31 %
1987	0.25	0.37	0.33	0.29	0.43	0.74
1988	0.21	0.26	0.23	0.37	0.51	0.67
1989	0.24	0.17	0.21	0.35	0.21	0.67
1990	0.20	0.26	0.21	0.32	0.20	0.87
1991	0.24	0.31	0.27	0.25	0.19	0.80
1992	0.36	0.28	0.14	0.16	0.17	0.55
1993	0.15	0.23	0.15	0.20	0.32	0.38
1994	0.15	0.23	0.09	0.16	0.33	0.37
Avg.	0.23 %	0.27 %	0.20 %	0.26 %	0.30 %	0.63 %
Jan.1995	0.16 %	0.15 %	0.07 %	0.14 %	0.42 %	0.34 %
Feb.1995	0.12	0.13	0.07	0.12	0.41	0.33
Mar.1995	0.11	0.12	0.08	0.11	0.41	0.33
Apr.1995	0.09	0.08	0.10	0.13	0.40	0.33
May 1995	0.09	0.10	0.11	0.12	0.39	0.30
Jun.1995	0.10	0.15	0.11	0.10	0.41	0.33
Jul.1995	0.09	0.17	0.10	0.12	0.41	0.37
Aug.1995	0.05	0.18	0.12	0.10	0.41	0.40
Sep.1995	0.06	0.20	0.14	0.09	0.36	0.36
Oct.1995	0.07	0.22	0.16	0.08	0.36	0.36
Nov.1995	0.09	0.23	0.21	0.07	0.38	0.35
Dec.1995	0.09	0.25	0.20	0.07	0.40	0.33
Avg.	0.10 %	0.17 %	0.12 %	0.10 %	0.40 %	0.35 %
Jan.1996	0.10 %	0.26 %	0.20 %	0.08 %	0.42 %	0.26 %
Feb.1996	0.09	0.26	0.17	0.12	0.41	0.23
Mar.1996	0.10	0.24	0.18	0.14	0.42	0.28
Apr.1996	0.10	0.25	0.19	0.11	0.43	0.30
May 1996	0.06	0.23	0.19	0.15	0.47	0.24
Jun.1996	0.04	0.27	0.19	0.12	0.45	0.30
Jul.1996	0.05	0.30	0.19	0.10	0.42	0.32
Aug.1996	0.07	0.30	0.18	0.06	0.41	0.40
Sep.1996	0.08	0.25	0.17	0.09	0.40	0.39
Oct.1996	0.10	0.27	0.17	0.07	0.38	0.36
Nov.1996	0.11	0.30	0.17	0.05	0.38	0.36
Dec.1996	0.11	0.31	0.15	0.05	0.39	0.37
Avg.	0.09 %	0.27 %	0.18 %	0.10 %	0.41 %	0.32 %
Jan. 1997	0.15 %	0.28 %	0.09 %	0.06 %	0.41 %	0.36 %
Feb. 1997	0.13	0.33	0.04	0.05	0.38	0.34
Mar. 1997	0.13	0.30	0.03	0.06	0.39	0.33
Avg.	0.14 %	0.31 %	0.07 %	0.05 %	0.39 %	0.35 %

Notes: (1) All Yields are distributed yields.
(2) Closing yields on March 13, 1997.

Source of Information: Moody's Investors Service

Interest Rate Trends - Historical and Projected
Estimates of the Consumer Price Index,
GDP Implicit Price Deflator(1) and Interest Rates for 1997

	Estimated Average 1997					
	Consumer Price Index(2)	GDP Implicit Price Deflator (2)	Prime Rate(2)	A Rated Public Utility Bonds(3)	Treasury Bonds(2)	Treasury Bills(2)
The Value Line Investment Survey	2.8%	2.2%	8.4%	N/A	7.2%	5.2%
Standard & Poor's Corp.	2.7	1.9	N/A	N/A	6.8	5.3
Blue Chip Financial Forecasts(4)	3.0	2.4	8.3	7.7%	6.6	5.2

Notes:

(1) Based upon an annual rate of increase or percent change.

(2) Based on estimated data for the year 1997.

(3) The average spread in yield during the five years ended 1996 between public utility bonds rated AAA and AA is about 0.17%; between AA and A is about 0.14%; and between A and BBB is about 0.33%. A rated public utility bonds are estimated by Blue Chip Financial Forecasts to yield 7.7% for the four-quarter period ending December 31, 1997. These forecasts suggest that the BBB rated public utility bonds average yield will be about 8.0%, A rated about 7.7% and AA rated about 7.6%. Actual March 13, 1997 distributed yields on public utility bonds for AAA, AA, A, and BBB ratings are 7.75%, 7.88%, 7.91%, and 8.30%, respectively (page 1 of this Schedule).

(4) Average for the four-quarter period ending December 31, 1997.

Source of Information: Value Line Investment Survey - Selection & Opinion, February 21, 1997
Standard & Poor's Trends & Projections, February 20, 1997
Blue Chip Financial Forecasts, March 1, 1997
Wall Street Journal, March 20, 1997
Moody's Investors Service

PECO Energy Company
Rate of Return on Average Book Common Equity (1)
Historic Comparison of PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Years 1986 - 1995, Inclusive and 1997 Spot

Year	PECO Energy Company	Barometer Group of Nine Electric Companies (2)
1997 Spot (3)	11.0 %	11.3 %
1995	13.3	12.0
1994	9.1	10.0
1993	13.1	11.3 (4)
1992	10.6	11.7
1991	12.5	11.9
1990	7.2 (5)	11.9 (6)
1989	13.5	12.1 (7)
1988	13.4	12.4 (8)
1987	13.0	13.4 (9)
1986	14.2	13.4
5 Year Average 1991 - 1995	11.7 %	11.4 %
5 Year Average 1986 - 1990	12.3 %	12.6 %

See page 2 of this schedule for Notes.

PECO Energy Company
Rate of Return on Average Book Common Equity (1)
Historic Comparison of PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Years 1986 - 1995, Inclusive and 1997 Spot

Notes:

(1) Rate of Return on Average Book Common Equity = income available for common equity divided by average of beginning and ending year's balance of book common equity.

(2) Arithmetic average of achieved results for all individual companies in the group.

(3) Spot 1997 rate of return on average book common equity = latest 12 months reported earnings per share divided by 1995 year-end book value per share.

(4) Excludes $200.400 million in disallowed Clinton Station after-tax post-construction costs for Illinova Corporation and $222.759 after-tax non-recurring write-off of a portion of the Zimmer Generating Station for CINergy Corporation. If these costs were included, the 1993 average rate of return for the Barometer Group would have been 8.1%.

(5) Excludes $250.000 million, after-tax, of Limerick Unit No. 2 disallowances. If these costs were included, the 1990 average rate of return for PECO Energy Company would have been 0.4%.

(6) Excludes $135.618 million in disallowed Clinton Station after-tax post-construction costs for Illinova Corporation. If these costs were included, the 1990 average rate of return for the Barometer Group would have been 10.9%.

(7) Excludes $106.280 million non-recurring after-tax charge relative to Department of Public Utilities and Wholesale Settlement Agreements for Boston Edison Company, $345.762 in disallowed Clinton Station after-tax post-construction costs for Illinova Corporation and an aggregate $862.485 in after-tax write-offs due to the Project Olive Branch Settlements for Entergy Corporation. If these costs were included, the 1989 average rate of return for the Barometer Group would have been 6.1%.

(8) Excludes $624.335 million in after-tax value of non-recurring disallowed plant costs for DTE Energy Company. If these costs were included, the 1988 average rate of return for the Barometer Group would have been 9.7%.

(9) Excludes $91.311 million in after-tax non-recurring write-off of a portion of the Zimmer Generating Station for CINergy Corporation and $72.900 million after-tax write-off of previously deffered Grand Gulf 1 Costs for Entergy Corporation. If these costs were included, the 1987 average rate of return for the Barometer Group would have been 12.2%.

Source of Information:

Standard & Poor's Compustat Services, Inc.,
Utility Compustat II
Moody's Public Utility Manuals
Annual Reports to Shareholders

PECO Energy Company
Market / Book Ratio (1)
Historic Comparison of PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Years 1986 - 1995, Inclusive and 1997 Spot

Year	PECO Energy Company Average Book Value	PECO Energy Company Market/ Book Ratio	Barometer Group of Nine Electric Companies (2)
1997 Spot (3)	$20.39	100.5 %	143.7 %
1995	19.90	136.9	135.8
1994	19.33	138.7	128.3
1993	18.74	157.4	149.8
1992	17.96	137.5	138.1
1991	17.19	126.5	131.2
1990	17.18	110.6	118.3
1989	17.52	124.5	113.3
1988	17.29	110.3	96.4
1987	17.83	119.9	101.0
1986	18.22	115.3	108.3
5 Year Average 1991 - 1995		139.4 %	136.6 %
5 Year Average 1986 - 1990		116.1 %	107.4 %

Notes:
(1) Market / Book Ratio = average of yearly high-low market price divided by *average beginning and ending year's book value per share.*
(2) Arithmetic average of achieved results for all individual companies in the group.
(3) Spot 1997 Market / Book Ratio = spot market price on 03/19/97 divided by 1995 year-end book value per share. The market price of a share of PECO Energy Company on 03/19/97 was $20.50.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II

PECO Energy Company
Stock Price and Interest Rates at Peaks
and Troughs of Last Several Business Cycles

Official Turning Points in Business Cycle	Dow Jones Industrial (2) Avg. Index	Dow Jones Industrial (2) % Chng.	Dow Jones Utility (2) Avg. Index	Dow Jones Utility (2) % Chng.	Average Yield on 'A' Public Util. Bonds
Jan. 1962 (Trough)	707.5		125.7		4.65%
Dec. 1969 (Peak)	787.5	11.3%	108.2	(13.9%)	8.59
Nov. 1970 (Trough)	774.2	(2.0)	111.3	2.9	8.79
Nov. 1973 (Peak)	883.3	14.1	93.4	(16.1)	8.15
Mar. 1975 (Trough)	765.0	(13.4)	78.0	(16.5)	9.72
Jan. 1980 (Peak)	851.1	11.3	108.6	39.2	12.27
July 1980 (Trough)	904.2	6.2	113.6	4.6	12.26
July 1981 (Peak)	946.1	4.6	107.8	(5.1)	16.21
Nov. 1982 (Trough)	1025.7	8.4	119.3	10.7	14.46
Jan. 22, 1987	-	-	227.8(1)	90.9	8.86
Aug. 25, 1987	2722.4(1)	165.4	-	-	10.47
Oct. 19, 1987	1738.4	(36.1)	161.0	(29.3)	11.75
July 1990 (Peak)	2905.2	67.1	210.0	30.4	9.75
Mar. 1991 (Trough)	2914.4	0.3	214.3	2.0	9.55
March 19, 1997	6877.68	136.0	221.4	3.3	7.91 (3)

Notes: (1) Peak of market values prior to October 19, 1987.
(2) Average of high and low for the month.
(3) Latest available information at March 13, 1997.

Source of Information: Business Conditions Digest
Moody's Public Utility Manual 1985
Moody's Municipal and Government Manual, 1984
Standard and Poor's Statistical Service
Security Price Index and Current Statistics
Moody's Investors Service
Wall Street Journal, March 20, 1997

PECO Energy Company
Average Investment Horizon (1) and Current Institutional Holdings (2) for PECO Energy Company and the Barometer Group of Nine Electric Companies for the years 1991 - 1995

	Common Stock Turnover Rate in Years						February 1997
	1995	1994	1993	1992	1991	Five-Year Average 1991-1995	Percentage of Institutional Holdings (2)
PECO Energy Company	2.1	2.1	2.3	2.1	2.4	2.2	42.1 %
Barometer Group of Nine Electric Companies							
American Electric Power Co., Inc.	2.3	2.1	2.7	2.8	2.6	2.5	36.1 %
Boston Edison Company	2.0	1.8	2.4	1.6	2.3	2.0	33.3
CINergy Corporation	2.2	2.4	2.0	2.2	2.0	2.2	50.2
DQE, Inc.	2.5	2.7	2.8	2.4	2.7	2.6	36.1
DTE Energy Company	2.1	1.7	2.2	2.5	2.7	2.2	36.8
Entergy Corp.	1.7	1.5	1.5	1.8	1.9	1.7	68.7
GPU, Inc.	1.7	1.5	1.6	1.5	2.3	1.7	61.1
Illinova Corporation	1.6	1.3	2.1	1.8	2.0	1.8	63.1
PP&L Resources, Inc.	2.0	2.5	4.2	4.2	4.9	3.6	29.3
Average	2.0	1.9	2.4	2.3	2.6	2.3	46.1 %

Notes: (1) The average investment horizon is calculated by dividing average common shares outstanding by common shares traded.

(2) The percentage of institutional holdings is calculated by dividing the number of shares held by institutions by the number of shares outstanding.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II
Standard & Poor's Stock Guide

PECO Energy Company
Earnings / Price Ratio (1)
Historic Comparison of PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Years 1986 - 1995, Inclusive and 1997 Spot

Year	PECO Energy Company Earnings Per Share	PECO Energy Company Earnings/ Price Ratio	Barometer Group of Nine Electric Companies (2)
1997 Spot (3)	$2.24	10.9 %	8.1 %
1995	2.64	9.7	8.9
1994	1.76	6.6	7.7
1993	2.45	8.3	7.7 (4)
1992	1.90	7.7	8.4
1991	2.15	9.9	8.9
1990	0.07	6.5 (5)	9.8 (6)
1989	2.36	10.8	10.3 (7)
1988	2.33	12.2	13.0 (8)
1987	2.33	10.9	14.0 (9)
1986	2.59	12.3	12.8
5 Year Average 1991 - 1995		8.4 %	8.3 %
5 Year Average 1986 - 1990		10.5 %	12.0 %

See page 2 of this schedule for Notes.

PECO Energy Company
Earnings / Price Ratio (1)
Historic Comparison of PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Years 1986 - 1995, Inclusive and 1997 Spot

Notes:

(1) Earnings / Price Ratio = latest reported earnings per share divided by average yearly high-low market price.

(2) Arithmetic average of achieved results for all individual companies in the group.

(3) Spot 1997 Earnings / Price Ratio = latest 12 months earnings per share divided by spot market price on 03/19/97. The market price of PECO Energy Company common stock on 03/19/97 was $20.50.

(4) Excludes $200.400 million in disallowed Clinton Station after-tax post-construction costs for Illinova Corporation and $222.759 after-tax non-recurring write-off of a portion of the Zimmer Generating Station for CINergy Corporation. If these costs were included, the 1993 earnings/price ratio for the Barometer Group would have been 5.3%.

(5) Excludes $250.000 million, after-tax, of Limerick Unit No. 2 disallowances. If these costs were included, the 1990 earnings/price ratio for PECO Energy Company would have been 0.4%.

(6) Excludes $135.618 million in disallowed Clinton Station after-tax post-construction costs for Illinova Corporation. If these costs were included, the 1990 earnings/price ratio for the Barometer Group would have been 8.5%.

(7) Excludes $106.280 million non-recurring after-tax charge relative to Department of Public Utilities and Wholesale Settlement Agreements for Boston Edison Company, $345.762 in disallowed Clinton Station after-tax post-construction costs for Illinova Corporation and an aggregate $862.485 in after-tax write-offs due to the Project Olive Branch Settlements for Entergy Corporation. If these costs were included, the 1989 earnings/price ratio for the Barometer Group would have been 3.3%.

(8) Excludes $624.335 million in after-tax value of non-recurring disallowed plant costs for DTE Energy Company. If these costs were included, the 1988 earnings/price ratio for the Barometer Group would have been 9.8%.

(9) Excludes $91.311 million in after-tax non-recurring write-off of a portion of the Zimmer Generating Station for CINergy Corporation and $72.900 million after-tax write-off of previously deffered Grand Gulf 1 Costs for Entergy Corporation. If these costs were included, the 1987 earnings/price ratio for the Barometer Group would have been 12.8%.

Source of Information:

Standard & Poor's Compustat Services, Inc.,
Utility Compustat II
Moody's Public Utility Manuals
Annual Reports to Shareholders

PECO Energy Company
Common Dividend Yield (1) and Dividend Payout Ratio (2)
Historic Comparison of PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Years 1986 - 1995, Inclusive and 1997 Spot

	PECO Energy Company			Barometer Group of Nine Electric Companies (3)	
Year	Dividends Per Share	Dividend Payout Ratio	Dividend Yield	Dividend Payout Ratio	Dividend Yield
1997 Spot (4)	$ 1.80	80.7 %	8.8 %	78.4 %	6.2 %
1995	1.65	62.4	6.1	71.9	6.3
1994	1.55	87.9	5.8	89.9	6.5
1993	1.43	58.4	4.8	73.1 (5)	5.4
1992	1.33	69.8	5.4	70.8	5.8
1991	1.23	57.1	5.6	66.1	5.8
1990	1.45	116.9 (6)	7.6	59.0 (7)	6.1
1989	2.20	93.1	10.1	84.4 (8)	7.1
1988	2.20	94.7	11.5	70.2 (9)	8.2
1987	2.20	94.8	10.3	57.3 (10)	7.2
1986	2.20	85.0	10.5	57.2	6.7
5 Year Average 1991 - 1995		67.1 %	5.5 %	74.4 %	6.0 %
5 Year Average 1986 - 1990		96.9 %	10.0 %	65.6 %	7.1 %

See page 2 of this schedule for Notes.

PECO Energy Company
Common Dividend Yield (1) and Dividend Payout Ratio (2)
Historic Comparison of PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Years 1986 - 1995, Inclusive and 1997 Spot

Notes:

(1) Dividend Yield = yearly dividends per share divided by average yearly high-low market price.
(2) Dividend Payout Ratio = dividends divided by income available for common equity.
(3) Arithmetic average of achieved results for all individual companies in the group.
(4) The 1997 spot dividend payout ratio = the current annualized dividend per share divided by latest reported 12 months earnings per share. The 1997 spot dividend yield = current annualized dividend per share by the spot market price on 03/19/97. The market price of PECO Energy Company common stock on 03/19/97 was $20.50.
(5) Excludes $200.400 million in disallowed Clinton Station after-tax post-construction costs for Illinova Corporation and $222.759 after-tax non-recurring write-off of a portion of the Zimmer Generating Station for CINergy Corporation. If these costs were included, the 1993 dividend payout ratio for the Barometer Group would have been 2.8%.
(6) Excludes $250.000 million of Limerick Unit No. 2 disallowances. If these costs were included, the 1990 dividend payout ratio for PECO Energy Company would have been 2007.2%.
(7) Excludes $135.618 million, after-tax, in disallowed Clinton Station after-tax post-construction costs for Illinova Corporation. Because Illinova Corporation paid no common dividends in 1990, even if these costs were included, the 1990 dividend payout ratio for the Barometer Group would have been 59.0%.
(8) Excludes $106.280 million non-recurring after-tax charge relative to Department of Public Utilities and Wholesale Settlement Agreements for Boston Edison Company, $345.762 in disallowed Clinton Station after-tax post-construction costs for Illinova Corporation and an aggregate $862.485 in after-tax write-offs due to the Project Olive Branch Settlements for Entergy Corporation. If these costs were included, the 1989 dividend payout ratio for the Barometer Group would have been 13.6%.
(9) Excludes $624.335 million in after-tax value of non-recurring disallowed plant costs for DTE Energy Company. If these costs were included, the 1988 dividend payout ratio for the Barometer Group would have been 52.5%.
(10) Excludes $91.311 million in after-tax non-recurring write-off of a portion of the Zimmer Generating Station for CINergy Corporation and $72.900 million after-tax write-off of previously deffered Grand Gulf 1 Costs for Entergy Corporation. If these costs were included, the 1987 dividend payout ratio for the Barometer Group would have been 63.1%.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II
Moody's Public Utility Manuals
Annual Reports to Shareholders

PECO ENERGY COMPANY
CAPITALIZATION AND FINANCIAL STATISTICS
1991 - 1995, INCLUSIVE

	1995	1994	1993	1992	1991	
AMOUNT OF CAPITAL EMPLOYED	(THOUSANDS OF DOLLARS)					
TOTAL PERMANENT CAPITAL	$9,905,400	$10,055,330	$10,203,690	$10,188,720	$10,292,390	
SHORT-TERM DEBT	0.	11,500	119,350	110,500	0.	
TOTAL CAPITAL EMPLOYED	$9,905,400	$10,066,830	$10,323,040	$10,299,220	$10,292,390	
INDICATED AVERAGE CAPITAL COST RATES (1)						
LONG TERM DEBT	7.8%	7.4%	7.5%	8.3%	9.1%	
PREFERRED STOCK	7.4	7.6	7.8	8.7	8.8	
FINANCIAL RATIOS-MARKET BASED						5 YEAR AVERAGE
EARNINGS/PRICE RATIO	9.7%	6.6%	8.3%	7.7%	9.9%	8.4%
MARKET/AVERAGE BOOK RATIO	136.9	138.7	157.4	137.5	126.5	139.4
DIVIDEND YIELD	6.1	5.8	4.8	5.4	5.6	5.5
DIVIDEND PAYOUT RATIO	62.4	87.9	58.4	69.8	57.1	67.1
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	48.3%	51.3%	52.2%	54.1%	55.0%	52.2%
PREFERRED STOCK	6.0	5.9	6.0	6.4	7.2	6.3
COMMON EQUITY	45.7	42.8	41.8	39.5	37.8	41.5
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	48.3%	51.4%	52.8%	54.6%	55.0%	52.4%
PREFERRED STOCK	6.0	5.9	5.9	6.4	7.2	6.3
COMMON EQUITY	45.7	42.7	41.3	39.0	37.8	41.3
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
COVERAGES-INCLUDING ALL AFUDC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.5x	2.6x	3.0x	2.4x	2.5x	2.8x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.5	2.0	2.3	1.9	1.9	2.1
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.3	1.8	2.0	1.7	1.7	1.9
COVERAGES-EXCLUDING ALL AFUDC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.4x	2.6x	3.0x	2.3x	2.4x	2.7x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.0	2.2	1.9	1.9	2.1
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.2	1.8	2.0	1.7	1.7	1.9
QUALITY OF EARNINGS						
OTHER INC./PRE-TAX GROSS INC. INCL. AFUDC (4)	5.7%	4.1%	2.5%	(6.5%)	3.6%	1.9%
AFUDC/INCOME AVAILABLE FOR COMMON EQUITY	4.6	5.7	4.4	4.9	4.9	4.9
EFFECTIVE INCOME TAX RATE	40.6	36.4	38.3	31.9	37.8	37.0
NET CASH FLOW/CAPITAL EXPENDITURES (5)	182.0	104.6	164.5	159.7	227.9	167.7
FUNDS FROM OPERATIONS/PERMANENT CAPITAL (6)	13.8	9.4	12.2	12.3	13.9	12.3
FUNDS FROM OPERATIONS/TOTAL DEBT (7)	28.6	18.2	22.8	22.2	25.4	23.4
FUNDS FROM OPERATIONS/INTEREST COVERAGE (8)	4.2x	3.2x	3.6x	3.4x	3.5x	3.6x
COMMON DIVIDEND COVERAGE (9)	3.7	2.6	3.8	4.1	5.1	3.9

SEE PAGE 2 FOR NOTES.

PECO Energy Company
Capitalization and Financial Statistics
1991-1995, Inclusive

Notes:

(1) Computed by relating actual long-term debt interest or preferred stock dividends booked to average of beginning and ending long-term debt or preferred stock reported to be outstanding.

(2) Coverages - including all AFUDC represent the number of times available earnings, including all AFUDC (allowance for funds used during construction), as reported in its entirety included as income, cover fixed charges. AFUDC includes allowance for borrowed and other funds used during construction.

(3) Coverages - excluding all AFUDC represent the number of times available earnings, excluding all AFUDC, cover fixed charges.

(4) Other Income / before-income tax gross income including AFUDC is non-operating income (net of expenses and non-income taxes) including all AFUDC as reported in its entirety, as a percentage of income available for fixed charges, including all AFUDC, before income taxes.

(5) Net cash flow / capital expenditures is the percentage of capital expenditures, excluding all AFUDC, provided by funds from operations, excluding all AFUDC, and after payment of all cash dividends.

(6) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC), as a percentage of permanent capital (long-term debt, current maturities and preferred and preference stock and common equity).

(7) Funds from operations (as defined in Note 6), as a percentage of ending total debt.

(8) Funds from operations (as defined in Note 6) plus interest charges divided by interest charges.

(9) Common dividend coverage is the relationship of internally generated funds from operations excluding all AFUDC, and after payments of preferred stock dividends to common dividends.

Bond Ratings
February 1997

	Moody's	S&P
PECO Energy Company	Baa1	BBB+

Source of Information: PECO Energy Company 1994 and 1995 Annual Reports to Shareholders
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Moody's Investors Service
Standard & Poor's Utility Rating Service

Exhibit JFBr-1
Schedule 9
Page 1 of 3

BAROMETER GROUP OF NINE ELECTRIC COMPANIES
CAPITALIZATION AND FINANCIAL STATISTICS (1)
1991 - 1995, INCLUSIVE

	1995	1994	1993	1992	1991	
AMOUNT OF CAPITAL EMPLOYED			(THOUSANDS OF DOLLARS)			
TOTAL PERMANENT CAPITAL	$6,754,050	$6,674,490	$6,453,020	$5,907,410	$5,864,820	
SHORT-TERM DEBT	149,750	188,060	138,100	103,630	113,670	
TOTAL CAPITAL EMPLOYED	$6,903,800	$6,862,550	$6,591,120	$6,011,040	$5,978,490	
	=========	=========	=========	=========	=========	
INDICATED AVERAGE CAPITAL COST RATES (2)						
LONG TERM DEBT	7.0%	7.2%	7.5%	8.3%	8.4%	
PREFERRED STOCK	7.5	6.8	7.2	7.7	7.7	
FINANCIAL RATIOS-MARKET BASED						5 YEAR AVERAGE
EARNINGS/PRICE RATIO	8.9%	7.7%	5.3%	8.4%	8.9%	7.8%
MARKET/AVERAGE BOOK RATIO	135.8	128.3	149.8	138.1	131.2	136.6
DIVIDEND YIELD	6.3	6.5	5.4	5.8	5.8	6.0
DIVIDEND PAYOUT RATIO	71.9	89.9	2.8	70.8	66.1	60.3
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	50.3%	51.1%	51.7%	51.7%	52.7%	51.5%
PREFERRED STOCK	6.4	7.4	7.4	7.8	8.1	7.4
COMMON EQUITY	43.3	41.5	40.9	40.5	39.2	41.1
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	51.7%	52.8%	53.0%	52.9%	53.8%	52.8%
PREFERRED STOCK	6.2	7.1	7.2	7.6	7.9	7.2
COMMON EQUITY	42.1	40.1	39.8	39.5	38.3	40.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
COVERAGES-INCLUDING ALL AFUDC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.3x	2.7x	2.6x	2.7x	2.6x	2.8x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.1	1.9	2.2	2.1	2.1
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.2	1.9	1.7	1.9	1.8	1.9
COVERAGES-EXCLUDING ALL AFUDC (4)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.3x	2.6x	2.5x	2.7x	2.5x	2.7x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.1	1.9	2.1	2.0	2.1
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.1	1.9	1.7	1.9	1.8	1.9
QUALITY OF EARNINGS						
OTHER INC./PRE-TAX GROSS INC. INCL. AFUDC (5)	4.7%	(4.9%)	(30.6%)	7.2%	8.2%	(3.1%)
AFUDC/INCOME AVAILABLE FOR COMMON EQUITY	2.9	5.2	(0.7)	4.8	8.4	4.1
EFFECTIVE INCOME TAX RATE	37.5	30.8	31.5	32.0	31.3	32.6
NET CASH FLOW/CAPITAL EXPENDITURES (6)	153.4	128.1	134.2	125.9	135.9	135.5
FUNDS FROM OPERATIONS/PERMANENT CAPITAL (7)	11.9	11.4	11.2	10.8	10.1	11.1
FUNDS FROM OPERATIONS/TOTAL DEBT (8)	22.3	20.9	20.6	20.0	18.4	20.4
FUNDS FROM OPERATIONS/INTEREST COVERAGE (9)	4.0x	3.9x	3.7x	3.4x	3.1x	3.6x
COMMON DIVIDEND COVERAGE (10)	3.5	3.5	3.6	3.4	5.1	3.8

SEE PAGE 2 FOR NOTES.

Barometer Group of Nine Electric Companies
Capitalization and Financial Statistics
1991-1995, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.

(2) Computed by relating actual long-term debt interest or preferred stock dividends booked to average of beginning and ending long-term debt or preferred stock reported to be outstanding.

(3) Coverages - including all AFUDC represent the number of times available earnings, including all AFUDC (allowance for funds used during construction), as reported in its entirety included as income, cover fixed charges. AFUDC includes allowance for borrowed and other funds used during construction.

(4) Coverages - excluding all AFUDC represent the number of times available earnings, excluding all AFUDC, cover fixed charges.

(5) Other Income / before-income tax gross income including AFUDC is non-operating income (net of expenses and non-income taxes) including all AFUDC as reported in its entirety, as a percentage of income available for fixed charges, including all AFUDC, before income taxes.

(6) Net cash flow / capital expenditures is the percentage of capital expenditures, excluding all AFUDC, provided by funds from operations, excluding all AFUDC, and after payment of all cash dividends.

(7) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC), as a percentage of permanent capital (long-term debt, current maturities and preferred and preference stock and common equity).

(8) Funds from operations (as defined in Note 6), as a percentage of ending total debt.

(9) Funds from operations (as defined in Note 6) plus interest charges divided by interest charges.

(10) Common dividend coverage is the relationship of internally generated funds from operations excluding all AFUDC, and after payments of preferred stock dividends to common dividends.

Selection Criteria:

The criteria used in the selection of this barometer group were to include those companies: 1) with an S.I.C. Code of 4911 (Electric Services) or 4931 (Electric and Other Services Combined): 2) with common stock which is actively traded; 3) which operate in the Northeastern, Great Lakes, North Central, South Central or Southeastern region of the continental United States (in conformance with the most recent regional groupings made by the Federal Energy Regulatory Commission's Bureau of Power); 4) with 1995 permanent capital of at least $2 billion; 5) with at least 70% of 1995 operating revenues derived from electric operations; 6) with a Moody's bond rating of A3, Baa1 or Baa2 or a Standard & Poor's bond rating of A-, BBB+ or BBB; and 7) which have paid common dividends and have not cut their common dividends since 1992.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II

Barometer Group of Nine Electric Companies
Capitalization and Financial Statistics
1991-1995, Inclusive

The names of the companies are:

	Bond Ratings February 1997	
	Moody's	S&P
American Electric Power Co., Inc. (1)	A3	A-
Boston Edison Company	Baa2	BBB
CINergy Corporation (2)	A3	A-
DQE, Inc. (3)	Baa1	BBB+
DTE Energy Company (4)	A3	BBB+
Entergy Corp. (5)	Baa2	BBB
GPU, Inc. (6)	Baa1	BBB+
Illinova Corporation (7)	Baa1	BBB
PP&L Resources, Inc. (8)	A3	A-
Average (9)	Baa1	BBB+

Notes: (1) Ratings are a composite of those of American Electric Power WV, Columbus Southern Power Corp., Indiana Michigan Power Co., Kentucky Power, Kingsport Power Co., Ohio Power, and Wheeling

(2) Ratings are a composite of those of Cincinnati Gas & Electric, PSI Energy Inc. and Union Light Heat & Power Co.

(3) Ratings are those of Duquesne Light Co.

(4) Ratings are those of Detroit Edison Co.

(5) Ratings are a composite of those of Entergy Arkansas Inc., Entergy Gulf States Inc., Entergy Louisiana Inc., Entergy Mississippi Inc. and Entergy New Orleans Inc.

(6) Ratings are a composite of those of Jersey Central Power & Light, Metropolitan Edison and Pennsylvania Electric Co.

(7) Ratings are those of Illinois Power Co.

(8) Ratings are those of Pennsylvania Power & Light Co.

(9) From page 2 of Schedule 11.

Source of Information: Moody's Investors Service
Standard & Poor's Utility Rating Service

PECO Energy Company

Comparison of Statistical Data for PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Year Ended December 31, 1995

		PECO Energy Company	Barometer Group of Nine Electric Companies (1)
(A)	Total Capitalization ($000s)	$9,905,403	$6,903,805
(B)	Total Operating Revenues ($000s)	4,186,152	3,295,361
(C)	Percent of Total Revenues Derived from Electric Operations	90.2%	96.1%
(D)	Total Electric Sales (MMKWH)	48,531	51,980
(E)	Number of Electric Customers	1,501,450	1,506,942
(F)	Common Equity Ratio Based Upon Total Capital	45.7%	42.1%
(G)	Electric Generation Mix (1)		
	Steam:		
	Nuclear	68.7 %	26.3 %
	Coal (Some Wood)	21.7	60.8
	Gas, Oil and other	7.4	12.2
	Total	97.8 %	99.3 %
	Hydro	3.8	0.5
	Pumped Storage	4.7	0.5
	Gas Turbine	0.5	0.4
	Other Sources	0.0	0.0
	Energy Input from Pumped Storage	(6.8)	(0.7)
	Total	100.0 %	100.0 %

Notes: (1) Supporting information on page 2.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II
Company Uniform Statistical Reports

PECO Energy Company
Statistical Data for the Barometer Group of Nine Electric Companies
for the Year Ended December 31, 1995

	American Electric Power Co., Inc.	Boston Edison Company	CINergy Corp.	DQE, Inc.	DTE Energy Company	Entergy Corp. (1)	GPU, Inc.	Illinova Corp. (2)	PP&L Resources Inc. (1)
(A) Total Capitalization ($000s)	$10,837,757	$2,593,769	$5,835,206	$2,941,719	$7,957,879	$15,262,375	$6,531,045	$3,943,500	$6,230,998
(B) Total Operating Revenues ($000s)	5,670,328	1,628,503	3,031,433	1,220,162	3,635,544	6,274,425	3,804,656	1,641,400	2,751,798
(C) Percent of Total Revenues Derived from Electric Operations	100.0%	100.0%	86.2%	100.0%	99.3%	97.6%	100.0%	83.4%	98.0%
(D) Total Electric Sales (MMKWH)	120,653	16,378	51,842	15,403	48,942	103,465	45,753	22,681	42,705
(E) Number of Electric Customers	2,891,332	653,757	1,355,643	579,531	1,991,499	2,359,657	1,963,768	554,268	1,213,023
(F) Common Equity Ratio Based Upon Total Capital	40.0%	38.2%	43.7%	45.2%	43.1%	42.4%	45.6%	36.7%	41.7%
(G) Electric Generation Mix (1)									
Steam:									
Nuclear	11.2 %	42.6 %	0.0 %	31.3 %	10.9 %	38.0 %	38.5 %	28.0 %	36.4 %
Coal (Some Wood)	87.9	0.0	98.6	68.8	88.4	17.3	58.1	70.9	56.9
Gas, Oil and other	0.1	57.2	0.0	(0.1)	1.5	44.5	0.9	1.1	4.6
Total	99.2 %	99.8 %	98.6 %	100.0 %	100.8 %	99.8 %	97.5 %	100.0 %	97.9 %
Hydro	0.8	0.0	0.7	0.0	0.0	0.2	0.6	0.0	2.0
Pumped Storage	0.4	0.0	0.0	0.0	1.9	0.0	2.6	0.0	0.0
Gas Turbine	0.0	0.2	0.7	0.0	0.0	0.0	2.8	0.0	0.1
Other Sources	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Input from Pumped Stora	(0.4)	0.0	0.0	0.0	(2.7)	0.0	(3.5)	0.0	0.0
Total	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %

Notes: (1) 1994 Information. 1995 electric generation mix is unavailable.
(2) 1993 Information. 1994 and 1995 electric generation mix is unavailable.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II Company Uniform Statistical Reports

PECO Energy Company
Comparison of Statistical Data for PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Year Ended December 31, 1995

	PECO Energy Company	Barometer Group of Nine Electric Companies (1)
Customer Mix		
(A) In Dollars of Revenue ($):		
Residential	37.1 %	34.8 %
Commercial	19.6	31.9
Industrial	30.4	21.7
Other (1)	9.3	6.3
Sales for Resale	2.2	3.6
Other (Non-Ultimate) (2)	1.4	1.7
Total	100.0 %	100.0 %
(B) In Sales of MMKWH:		
Residential	22.4 %	25.6 %
Commercial	13.0	27.8
Industrial	32.9	28.3
Other (1)	29.9	14.1
Sales for Resale	1.8	4.2
Total	100.0 %	100.0 %
(C) In Number of Customers:		
Residential	90.1 %	88.6 %
Commercial	9.6	10.6
Industrial	0.2	0.5
Other (1)	0.1	0.3
Sales for Resale	0.0	0.0
Total	100.0 %	100.0 %

Notes: (1) Represents the percent of total electric revenues, MMKWH or customers not classified as commercial, industrial, or residential. It includes such items as electric service supplied to public street and highway lighting, other sales to public authorities (not for resale) and sales to railroads and railways.

(2) Represents percent of electric operating revenue from sources other than actual sales of electricity, such as forfeited discounts, miscellaneous service revenues, rent from electric property and interdepartmental rents.

(3) Supporting information on page 4.

Source of Information: Standard & Poor's Compustat Services, Inc.
Utility Compustat II
Company Uniform Statistical Reports

PECO Energy Company
Comparison of Statistical Data for PECO Energy Company
and the Barometer Group of Nine Electric Companies
for the Year Ended December 31, 1995

	American Electric Power Co., Inc.	Boston Edison Company	CINergy Corp.	DQE, Inc.	DTE Energy Company	Entergy Corp. (1)	GPU, Inc.	Illinova Corp. (2)	PP&L Resources Inc. (3)
Customer Mix									
(A) In Dollars of Revenue ($):									
Residential	34.5 %	27.3 %	36.8 %	34.1 %	33.5 %	35.6 %	40.5 %	36.5 %	34.2 %
Commercial	22.3	49.5	25.2	39.5	41.4	24.4	33.1	23.5	27.8
Industrial	28.3	9.1	24.3	15.7	20.2	29.6	20.5	28.6	19.3
Other (4)	12.0	10.8	7.8	4.7	2.8	6.0	3.5	8.5	0.9
Sales for Resale	1.2	1.5	4.1	1.4	1.3	2.5	1.0	2.9	16.3
Other (Non-Ultimate) (5)	1.7	1.8	1.8	4.6	0.8	1.9	1.4	0.0	1.5
Total	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %
(B) In Sales of MMKWH:									
Residential	25.4 %	21.8 %	27.7 %	21.9 %	26.6 %	26.8 %	32.4 %	21.0 %	26.5 %
Commercial	18.4	46.4	22.5	37.2	35.7	20.0	29.6	16.8	23.3
Industrial	36.8	9.4	31.4	21.0	28.2	40.9	26.2	38.2	23.0
Other (4)	18.4	21.6	15.0	19.4	8.8	10.1	11.3	22.4	0.0
Sales for Resale	1.0	0.8	3.4	0.5	0.7	2.2	0.5	1.6	27.2
Total	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %
(C) In Number of Customers:									
Residential	87.8 %	87.1 %	88.2 %	90.1 %	91.2 %	86.9 %	88.3 %	89.7 %	88.1 %
Commercial	11.0	12.1	10.9	9.3	8.7	11.0	11.1	10.1	11.4
Industrial	0.8	0.3	0.5	0.3	0.0	1.6	0.4	0.1	0.4
Other (4)	0.4	0.5	0.4	0.3	0.1	0.5	0.2	0.1	0.1
Sales for Resale	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %

Notes: (1) Customer mix based upon number of customers is for 1994. 1995 data are not available.

(2) Customer mix based upon number of customers is for 1993. 1994 and 1995 data are not available.

(3) Customer mix based upon operating revenues is for 1994. 1995 data are not available.

(4) Represents the percent of total electric revenues, MMKWH or customers not classified as commercial, industrial, or residential. It includes such items as electric service supplied to public street and highway lighting, other sales to public authorities (not for resale) and sales to railroads and

(5) Represents percent of electric operating revenue from sources other than actual sales of electricity, such as forfeited discounts, miscellaneous service revenues, rent from electric property and interdepartmental rents.

Source of Information: Standard & Poor's Compustat Services, Inc.
Utility Compustat II
Company Uniform Statistical Reports

PECO Energy Company
Comparison of Sales in Millions of Kilowatt Hours by Customer Class for
PECO Energy Company and the Barometer Group of Nine Electric Companies

	Sales in Millions of Kilowatt Hours			Percent Increase	
	1986	1991	1995	1995 over 1991	1995 over 1986
PECO Energy Company					
Residential	8,900.406	10,310.699	10,859.097	5.3 %	22.0 %
Commercial	4,022.352	5,284.167	6,299.519	19.2	56.6
Industrial	15,067.503	16,176.898	15,975.699	(1.2)	6.0
Barometer Group of Nine Electric Companies (1)					
Residential	9,708.710	11,182.537	13,721.583	22.7 %	41.3 %
Commercial	7,779.440	9,325.018	12,517.403	34.2	60.9
Industrial	11,950.701	13,289.856	16,887.671	27.1	41.3

Notes: (1) Supporting information on page 6.

Source of Information: Standard & Poor's Compustat Services, Inc.
Utility Compustat II
Company Uniform Statistical Reports

PECO Energy Company
Comparison of Sales in Millions of Kilowatt Hours by Customer Class for
the Barometer Group of Nine Electric Companies

	Sales in Millions of Kilowatt Hours			Percent Increase	
	1986	1991	1995	1995 over 1991	1995 over 1986
American Electric Power Co., Inc.					
Residential	23,232.406	27,457.597	30,620.000	11.5 %	31.8 %
Commercial	16,072.804	19,704.097	22,189.796	12.6	38.1
Industrial	34,191.007	39,481.796	44,366.699	12.4	29.8
Boston Edison Company					
Residential	3,048.453	3,382.306	3,563.626	5.4 %	16.9 %
Commercial	6,362.476	7,132.175	7,604.839	6.6	19.5
Industrial	1,837.262	1,684.864	1,538.218	(8.7)	(16.3)
CINergy Corp. (1)					
Residential	5,782.484	7,110.320	14,365.796	102.0 %	148.4 %
Commercial	4,182.437	5,293.539	11,647.898	120.0	178.5
Industrial	4,910.687	5,538.710	16,264.296	193.6	231.2
DQE, Inc.					
Residential	2,956.648	3,285.561	3,378.533	2.8 %	14.3 %
Commercial	4,723.902	5,450.144	5,728.902	5.1	21.3
Industrial	2,733.937	3,041.679	3,237.130	6.4	18.4
DTE Energy Company					
Residential	10,492.300	12,221.597	13,006.199	6.4 %	24.0 %
Commercial	7,500.605	8,873.292	17,470.898	96.9	132.9
Industrial	17,239.703	18,262.000	13,825.500	(24.3)	(19.8)
Entergy Corp.					
Residential	17,118.402	18,328.699	27,704.000	51.2 %	61.8 %
Commercial	11,539.000	13,163.898	20,719.000	57.4	79.6
Industrial	19,460.203	23,466.296	42,260.000	80.1	117.2
GPU, Inc.					
Residential	11,778.800	13,851.597	14,802.097	6.9 %	25.7 %
Commercial	9,654.027	12,335.597	13,543.296	9.8	40.3
Industrial	11,855.601	12,035.597	11,982.199	(0.4)	1.1
Illinova Corp.					
Residential	4,197.683	4,619.757	4,754.000	2.9 %	13.3 %
Commercial	2,821.336	3,111.432	3,804.000	22.3	34.8
Industrial	7,341.562	7,641.519	8,670.000	13.5	18.1
PP&L Resources Inc.					
Residential	8,771.210	10,385.398	11,300.000	8.8 %	28.8 %
Commercial	7,158.371	8,860.992	9,948.000	12.3	39.0
Industrial	7,986.343	8,456.242	9,845.000	16.4	23.3

Notes: (1) 1995 information reflects the acquisition of PSI Energy, Inc. in October 1994. 1986 and 1991 information does not reflect the acquisition.

Source of Information: Standard & Poor's Compustat Services, Inc.
Utility Compustat II
Company Uniform Statistical Reports

PECO Energy Company
Comparison of Bond Ratings for
PECO Energy Company and the
Barometer Group of Nine Electric Companies

Company	February 1997 Moody's Bond Rating: Bond Rating	Numerical Weighting (1)	Average Numerical Weighting	February 1997 Standard & Poor's Bond Rating: Bond Rating	Numerical Weighting (1)	Average Numerical Weighting	Standard & Poor's Business Position (2)	
PECO Energy Company	Baa1		8.0	BBB+		8.0	Somewhat Below Average	6.0
Barometer Group of Nine Electric Companies								
American Electric Power Co., Inc.								
American Electric Power WV	A3	7.0		A-	7.0		Somewhat Above Average	2.0
Columbus Southern Power Corp.	A3	7.0		A-	7.0		Somewhat Above Average	2.0
Indiana Michigan Power Co.	Baa1	8.0		A-	7.0		Somewhat Above Average	2.0
Kentucky Power	Baa1	8.0		BBB+	8.0		Somewhat Above Average	2.0
Kingsport Power Co.	NR	- -		NR	- -		Not Rated	0.0
Ohio Power	A3	7.0		A-	7.0		Somewhat Above Average	2.0
Wheeling Power Co.	NR	- -		NR	- -		Not Rated	0.0
Average	A3	7.4	7.4	A-	7.2	7.2	Somewhat Above Average	2.0
Boston Edison Company	Baa2		9.0	BBB		9.0	Average	4.0
CINergy Corporation								
Cincinnati Gas & Electric	A3	7.0		BBB+	8.0		High Average	3.0
PSI Energy Inc.	A2	6.0		A-	7.0		High Average	3.0
Union Light, Heat & Power Co.	A3	7.0		A-	7.0		Not Rated	0.0
Average	A3	7.0	7.0	A-	7.3	7.3	High Average	3.0
DQE, Inc.								
Duquesne Light Co.	Baa1		8.0	BBB+		8.0	Low Average	5.0
DTE Energy Company								
Detroit Edison Company	A3		7.0	BBB+		8.0	Somewhat Below Average	6.0

PECO Energy Company
Comparison of Bond Ratings for
PECO Energy Company and the
Barometer Group of Nine Electric Companies

Company	February 1997 Moody's Bond Rating: Bond Rating	Numerical Weighting (1)	Average Numerical Weighting	February 1997 Standard & Poor's Bond Rating: Bond Rating	Numerical Weighting (1)	Average Numerical Weighting	Standard & Poor's Business Position (2)	
Entergy Corp.								
Entergy Arkansas Inc.	Baa2	9.0		BBB	9.0		Low Average	5.0
Entergy Gulf States Inc.	Baa3	10.0		BBB-	10.0		Somewhat Below Average	6.0
Entergy Louisiana Inc.	Baa2	9.0		BBB	9.0		Low Average	5.0
Entergy Mississippi Inc.	Baa2	9.0		BBB	9.0		Low Average	5.0
Entergy New Orleans Inc.	Baa2	9.0		BBB	9.0		Low Average	5.0
Average	Baa2	9.2	9.2	BBB	9.2	9.2	Low Average	5.2
GPU, Inc.								
Jersey Central Power & Light	Baa1	8.0		BBB+	8.0		Low Average	5.0
Metropolitan Edison	Baa1	8.0		BBB+	8.0		Low Average	5.0
Pennsylvania Electric Co.	A3	7.0		A-	7.0		Average	4.0
Average	Baa1	7.7	7.7	BBB+	7.7	7.7	Low Average	4.7
Illinova Corporation								
Illinois Power Co.	Baa1		8.0	BBB		9.0	Low Average	5.0
PP&L Resources, Inc.								
Pennsylvania Power & Light Co.	A3		7.0	A-		7.0	Average	4.0
Average for Barometer Group of Nine Electric Companies	Baa1		8.0	BBB+		8.2	Average	4.7

Notes:
(1) As developed on page 2 of this Schedule.
(2) From Standard & Poor's Utility Rating Service, Financial Statistics for the 12 months ending September 30, 1996.

Source of Information:
Moody's Investors Service
Standard & Poor's Utility Rating Service

PECO Energy Company
Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings and
Standard & Poor's Business Position

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-

Numerical Weighting	Standard & Poor's Business Position
1.0	Above Average
2.0	Somewhat Above Average
3.0	High Average
4.0	Average
5.0	Low Average
6.0	Somewhat Below Average
7.0	Below Average

PECO Energy Company
Analysis of State Regulatory Evaluations for
PECO Energy Company and the
Barometer Group of Nine Electric Companies

Company	Jurisdiction	Rating	Numerical Weighting (1)	Average Numerical Weighting
PECO Energy Company	PA	Average 3		6.0
Barometer Group of Nine Electric Companies				
American Electric Power Co., Inc.	WV	Below Average 1	7.0	
	OH	Average 2	5.0	
	MI	Average 3	6.0	
	KY	Average 1	4.0	
	TN	Average 1	4.0	
	Average		5.2	5.2
Boston Edison Company	MA	Average 2		5.0
CINergy Corporation	OH	Average 2	5.0	
	IN	Above Average 2	2.0	
	KY	Average 1	4.0	
	Average		3.7	3.7
DQE, Inc.	PA	Average 3		6.0
DTE Energy Company	MI	Average 3		6.0
Entergy Corp.	AR	Average 3	6.0	
	TX	Below Average 1	7.0	
	LA	Below Average 2	8.0	
	MS	Average 1	4.0	
	Average		6.3	6.3
GPU, Inc.	NJ	Average 1	4.0	
	PA	Average 3	6.0	
	Average		5.0	5.0
Illinova Corporation	IL	Average 3		6.0
PP&L Resources, Inc.	PA	Average 3		6.0
Average for Barometer Group of Nine Electric Companies		Average 2 / Average 3		5.5

Notes: (1) As developed on page 2 of this schedule.

Source of Information: Regulatory Research Associates Inc.
Regulatory Focus - February 5, 1997

Numerical Assignment for Regulatory Research Associates, Inc.
State Regulatory Evaluations

Rating	Numerical Weighting
Above Average 1	1
Above Average 2	2
Above Average 3	3
Average 1	4
Average 2	5
Average 3	6
Below Average 1	7
Below Average 2	8
Below Average 3	9

PECO Energy Company
Latest Authorized Return Rate on Common Equity for
PECO Energy Company and the
Barometer Group of Nine Electric Companies

Company	Jurisdiction	Date Authorized	Return on Equity Authorized		Average Return on Equity Authorized
PECO Energy Company	PA (Elec)	4/19/90	12.75 %		
PECO Energy Company	PA (Gas)	1/15/88	13.15		
Average			12.95 %		12.95 %
Barometer Group of Nine Electric Companies					
American Electric Power Co., Inc.					
American Electric Power WV (1)	WV	12/27/96	N/A	(2)	
Columbus Southern Power Corp.	OH	5/12/92	12.46 %		
Indiana Michigan Power Co.	MI	2/12/91	13.00		
Kentucky Power	KY	12/4/84	16.50		
Kingsport Power Co.	TN	11/3/92	12.00		
Ohio Power	OH	3/23/95	12.81		
Wheeling Power Co.	WV	5/9/83	N/A	(2)	
Average			13.35 %		13.35 %
Boston Edison Company	MA	10/30/92			11.75 %
CINergy Corporation					
Cincinnati Gas & Electric	OH (Elec)	8/26/93	12.05 %	(3)	
Cincinnati Gas & Electric	OH (Gas)	12/12/96	11.96		
PSI Energy Inc.	IN	9/27/96	11.00		
Union Light, Heat & Power Co.	KY (Elec)	5/5/92	11.50		
Union Light, Heat & Power Co.	KY (Gas)	7/23/93	11.50		
Average			11.60 %		11.60 %
DQE, Inc.					
Duquesne Light Co.	PA	3/25/88			12.87 %
DTE Energy Company					
Detroit Edison Company	MI	1/21/94			11.00 %
Entergy Corp.					
Entergy Arkansas Inc.	AR	7/27/87	13.00 %		
Entergy Gulf States Inc.	TX	3/20/95	12.00		
Entergy Louisiana Inc.	LA	11/12/96	N/A	(2)	
Entergy Mississippi Inc.	MS	3/1/96	10.78		
Entergy New Orleans Inc.	LA (Elec)	3/25/86	N/A	(2)	
Entergy New Orleans Inc.	LA (Gas)	5/21/92	N/A	(2)	
Average			11.93 %		11.93 %
GPU, Inc.					
Jersey Central Power & Light	NJ	2/26/93	12.20 %		
Metropolitan Edison	PA	1/21/93	11.25		
Pennsylvania Electric Co.	PA	11/25/86	N/A	(2)	
Average			11.73 %		11.73 %
Illinova Corporation					
Illinois Power Co.	IL (Elec)	2/11/92	12.40 %		
Illinois Power Co.	IL (Gas)	4/6/94	11.24		
Average			11.82 %		11.82 %
PP&L Resources, Inc.					
Pennsylvania Power & Light Co.	PA	9/27/95			11.50 %
Average for Barometer Group of Nine Electric Companies					11.95 %

Notes:
(1) Formerly known as Appalachian Power Company.
(2) Stipulated, no Return on Equity specified.
(3) Return on Equity range of 11.4% to 12.7%.

Source of Information: *Regulatory Research Associates, Inc.* Regulatory Focus

PECO Energy Company
Comparison of Standard & Poor's Common Stock Ranking and
Value Line's Safety Ranking for PECO Energy Company
and the Barometer Group of Nine Electric Companies

	February 1997 Standard & Poor's Common Stock Ranking		
Company	Common Stock Ranking (1)	Numerical Weighting (2)	Value Line Safety Ranking (3)
PECO Energy Company	B	5.0	2.0
Barometer Group of Nine Electric Companies			
American Electric Power Co., Inc.	B+	4.0	3.0
Boston Edison Company	B+	4.0	3.0
CINergy Corporation	B	5.0	2.0
DQE, Inc.	A-	3.0	2.0
DTE Energy Company	A-	3.0	3.0
Entergy Corp.	B	5.0	4.0
GPU, Inc.	B+	4.0	3.0
Illinova Corporation	B	5.0	3.0
PP&L Resources, Inc.	A-	3.0	2.0
Average for Barometer Group of Nine Electric Companies	B+	4.0	2.8

See page 2 of this schedule for Notes.

PECO Energy Company
Comparison of Standard & Poor's Common Stock Ranking and
Value Line's Safety Ranking for PECO Energy Company
and the Barometer Group of Nine Electric Companies

Notes:

(1) Standard & Poor's rankings are based upon an appraisal of past performance of earnings and dividends and relative current standing measured against a scoring matrix determined by analysis of scores of a large and representative sample of stocks.

(2) *Numerical assignment for Standard & Poor's stock rankings are as follows:*

Numerical Stock Weighting	Standard & Poor's Stock Ranking
1	A+
2	A
3	A-
4	B+
5	B
6	B-
7	C
8	D

(3) Value Line's safety ranking is based on the stability of a company's market price adjusted for trends and other factors including company size, the penetration of markets, product market volatility, degree of financial leverage, earnings quality and overall condition of the balance sheet.

Source of Information: Standard & Poor's Stock Guide, March 1997
Value Line Investment Survey,
January 10, 1997 and March 14, 1997.

PECO Energy Company
Derivation of Dividend Yield for Use in the Discounted Cash Flow Model

	Dividend Yield			
	Spot (03-19-97) (1)	Average of Last 3 Months (2)	Average of Last 6 Months (3)	Average Dividend Yield (4)
PECO Energy Company	8.8 %	7.7 %	7.4 %	8.0 %
Barometer Group of Nine Electric Companies				
American Electric Power Co., Inc.	5.9 %	5.8 %	5.8 %	5.8 %
Boston Edison Company	7.2	7.0	7.4	7.2
CINergy Corporation	5.2	5.3	5.4	5.3
DQE, Inc.	4.8	4.7	4.7	4.7
DTE Energy Company	7.4	6.6	6.7	6.9
Entergy Corp.	7.1	6.6	6.6	6.8
GPU, Inc.	5.5	5.7	5.8	5.7
Illinova Corporation	5.2	4.6	4.4	4.7
PP&L Resources, Inc.	8.0	7.3	7.3	7.5
Average	6.3 %	6.0 %	6.0 %	6.1 %

Notes: (1) The spot dividend yield is the current annualized dividend per share divided by the spot market price at 03-19-97.

(2) The average 3-month dividend yield was computed by relating the indicated annualized dividend rate and market price on the last trading day of each of the three months ended February 28, 1997

(3) The average 6-month dividend yield was computed by relating the indicated annualized dividend rate and market price on the last trading day of each of the six months ended February 28, 1997

(4) Equal weight has been given to the 6-month average, 3-month average and spot dividend yield.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II
Security APL Quote Server, http://qs.secapl.com/

PECO Energy Company
Closing Market Prices
Spot, 3-Month Average and 6-Month Average

	Closing Market Prices			
	Spot (03-19-97) (1)	Average of Last 3 Months (2)	Average of Last 6 Months (3)	Average Closing Market Price (4)
PECO Energy Company	$20.500	$23.583	$24.208	$22.764
Barometer Group of Nine Electric Companies				
American Electric Power Co., Inc.	$41.000	$41.417	$41.333	$41.250
Boston Edison Company	26.250	26.917	25.417	26.195
CINergy Corporation	34.875	34.125	33.313	34.104
DQE, Inc.	28.625	29.083	28.896	28.868
DTE Energy Company	27.750	31.333	30.688	29.924
Entergy Corp.	25.500	27.083	27.229	26.604
GPU, Inc.	35.250	34.042	33.229	34.174
Illinova Corporation	23.750	26.292	26.521	25.521
PP&L Resources, Inc.	20.875	22.833	22.771	22.160
Average	$29.319	$30.347	$29.933	$29.867

Notes: (1) The spot closing market price is the spot market price at 03-19-97.

(2) The average 3-month was computed by averaging the closing market prices on the last trading day of each of the three months ended February 28, 1997

(3) The average 6-month was computed by averaging the closing market prices on the last trading day of each of the six months ended February 28, 1997

(4) Equal weight has been given to the 6-month average, 3-month average and spot closing market prices.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II
Security APL Quote Server, http://qs.secapl.com/

PECO Energy Company
Indicated Annualized Dividends Per Share
Spot, 3-Month Average and 6-Month Average

	Indicated Annualized Dividends Per Share			
	Spot (03-19-97) (1)	Average of Last 3 Months (2)	Average of Last 6 Months (3)	Average Indicated Annualized Dividends Per Share (4)
PECO Energy Company	$1.800	$1.800	$1.790	$1.797
Barometer Group of Nine Electric Companies				
American Electric Power Co., Inc.	$2.400	$2.400	$2.400	$2.400
Boston Edison Company	1.880	1.880	1.880	1.880
CINergy Corporation	1.800	1.800	1.787	1.796
DQE, Inc.	1.360	1.360	1.347	1.356
DTE Energy Company	2.060	2.060	2.060	2.060
Entergy Corp.	1.800	1.800	1.800	1.800
GPU, Inc.	1.940	1.940	1.940	1.940
Illinova Corporation	1.240	1.200	1.160	1.200
PP&L Resources, Inc.	1.670	1.670	1.670	1.670
Average	$1.794	$1.790	$1.783	$1.789

Notes: (1) The spot dividends per share are the indicated annualized dividends per share at 03-19-97.

(2) The average 3-month was computed by averaging the indicated annualized dividends per share on the last trading day of each of the three months ended February 28, 1997

(3) The average 6-month was computed by averaging the indicated annualized dividends per share on the last trading day of each of the six months ended February 28, 1997

(4) Equal weight has been given to the 6-month average, 3-month average and spot indicated annualized dividends per share.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II
Security APL Quote Server, http://qs.secapl.com/

PECO Energy Company
Historical and Projected Growth

	1	2	3	4	5	6	7	8	9
	Value Line Historical Five Year Growth Rate (1)		Value Line Projected 1994-'96 to 2000-'02 Growth Rate (1)			I/B/E/S Projected Five-Year Growth Rate (3)		Average of I/B/E/S and Value Line Projected Five-Year Growth in EPS (4)	Conclusion of Growth Rate (5)
	DPS	EPS	DPS	EPS	BR (2)	EPS	No. of Analysts		
PECO Energy Company	(4.5)%	(0.5)%	2.0 %	2.5 %	2.9 %	3.1 %	[18]	2.8 %	2.8 %
Barometer Group of Nine Electric Companies									
American Electric Power Co., Inc.	0.5 %	(2.5)%	0.5 % (6)	4.5 % (6)	4.6 %	2.8 %	[12]	3.7 %	3.7 %
Boston Edison Company	1.0	5.0	1.0 (6)	1.5 (6)	2.5	2.6	[10]	2.1	2.1
CINergy Corporation	3.5	1.5	3.0 (7)	5.0 (7)	3.9	4.8	[14]	4.9	4.9
DQE, Inc.	5.5	8.0	5.0 (6)	4.0 (6)	4.2	5.0	[15]	4.5	4.5
DTE Energy Company	4.0	1.5	1.0 (7)	2.5 (7)	4.8	2.7	[13]	2.6	2.6
Entergy Corp.	19.5	- -	0.5 (7)	12.5 (7)	3.9	4.2	[11]	8.4	8.4
GPU, Inc.	10.5	1.0	3.0 (6)	5.5 (6)	4.8	3.4	[12]	4.5	4.5
Illinova Corporation	(4.0)	20.0	9.5 (7)	10.0 (7)	6.4	6.0	[13]	8.0	8.0
PP&L Resources, Inc.	3.0	(0.5)	Nil (6)	2.5 (6)	3.0	2.7	[12]	2.6	2.6
Average	4.8 %	3.8 %	2.6 %	5.3 %	4.2 %	3.8 %		4.6 %	4.6 %

Notes:

(1) From Value Line Investment Survey, January 10, and March 14, 1997. Historical growth rates are five-year compound growth rates.
(2) From page 2 of this Schedule.
(3) Compound growth rates in earnings per share are the only projected growth rates available from the I/B/E/S monthly summary.
(4) Average of columns 4 and 6.
(5) Based upon the average of I/B/E/S and Value Line Projected Five-Year Growth in EPS as explained in Mr. Brennan's direct testimony.
(6) Projected growth rates: 1993 - 1995 to 2000 - 2002.
(7) Projected growth rates: 1993 - 1995 to 1999 - 2001.

Source of Information: Value Line Investment Survey, January 10, and March 14, 1997
I/B/E/S Custom Report, February 20, 1997

PECO Energy Company
Projected Internal Growth Rate

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	1996			2000 - 2002					2000 - 2002					
	Common Equity (%) (1)	Total Capital ($ mill) (1)	Common Equity ($ mill) (1)	Common Equity (%) (1)	Total Capital ($ mill) (1)	Common Equity ($ mill) (1)	Annual Common Equity Growth Rate (4)	ROE Adjustment Factor (5)	Return on Common Equity (1)	Return on Average Common Equity (6)	EPS (1)	DPS (1)	Retention Ratio (7)	Projected Internal Growth (8)
PECO Energy Company	49.90 %	$9,308.40 %	$4,644.89	51.00 %	$10,380.00	$5,293.80	2.65 %	1.01	10.50 %	10.61 %	$2.55	$1.84	27.8 %	2.9 %
Barometer Group of Nine Electric Companies														
American Electric Power Co., Inc.	43.70 % (9)	$9,923.50 (9)	$4,336.57	48.50 %	$11,465.00	$5,560.53	4.23 %	1.02	13.00 %	13.26 %	$3.60	$2.48	34.7 %	4.6 %
Boston Edison Company	45.10	2,296.50	1,035.72	58.00	2,225.00	1,290.50	4.50	1.02	10.00	10.20	2.50	1.88	24.8	2.5
CINergy Corporation	46.60 (9)	5,467.50 (9)	2,547.86	51.00 (10)	6,185.00 (10)	3,154.35	4.36 (11)	1.02	13.50	13.77	2.70	1.94	28.1	3.9
DQE, Inc.	46.90 (9)	2,835.30 (9)	1,329.76	53.50	3,325.00	1,778.88	4.97	1.02	11.00	11.22	2.60	1.62	37.7	4.2
DTE Energy Company	44.90 (9)	7,647.40 (9)	3,433.68	52.50 (10)	6,700.00 (10)	3,517.50	0.48 (11)	1.00	13.00	13.00	3.50	2.20	37.1	4.8
Entergy Corp.	44.60 (9)	14,507.00 (9)	6,470.12	45.50 (10)	16,300.00 (10)	7,416.50	2.77 (11)	1.01	10.00	10.10	3.05	1.86	39.0	3.9
GPU, Inc.	48.70 (9)	6,104.60 (9)	2,972.94	54.50	7,125.00	3,883.13	4.55	1.02	11.50	11.73	3.75	2.20	41.3	4.8
Illinova Corporation	43.80 (9)	3,488.90 (9)	1,528.14	57.00 (10)	3,350.00 (10)	1,909.50	4.56 (11)	1.02	12.00	12.24	3.25	1.55	52.3	6.4
PP&L Resources, Inc.	43.10 (9)	6,030.80 (9)	2,599.27	54.50	5,800.00	3,161.00	3.31	1.02	11.50	11.73	2.25	1.67	25.8	3.0
Average														4.2 %

Notes:
(1) From Value Line Investment Survey, January 10, and March 14, 1997.
(2) Column 1 * column 2.
(3) Column 4 * column 5.
(4) Five / six year compound growth rate in common equity from 1996 / 1995 to 2000-2002 or (((column 6 / column 3) ^ 1 / 5) - 1) or (((column 6 / column 3) ^ 1 / 6) -).
(5) 2 * ((1 + column 7) / (2 + column 7)) .
(6) Column 8 * column 9.
(7) 1 - (column 12 / column 11).
(8) Column 10 * column 13.
(9) 1995 data.
(10) 1999 - 2001.
(11) Five year compound growth rate in common equity from 1995 to 1999-2001 or (((column 6 / column 3) ^ 1 / 5) - 1).

Source of Information: Value Line Investment Survey, January 10, and March 14, 1997

PECO Energy Company
Discounted Cash Flow Model
Summary of Conclusion

	PECO Energy Company	Barometer Group of Nine Electric Companies
1. Dividend Yield (1)	8.0 %	6.1 %
2. Dividend Growth Component (2)	0.1	0.1
3. Yield	8.1	6.2
4. Growth Rate (3)	2.8	4.6
5. Indicated Return Rate	10.9 %	10.8 %

Notes: (1) From page 1 of Schedule 15.

(2) This reflects a growth rate component equal to one-half the conclusion of growth rate (from page 1 of Schedule 16) x Line No. 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, 8.0% x (1/2 x 2.8%) = 0.11%, rounded down to 0.1% for PECO Energy Company and 6.1% x (1/2 x 4.6%) = 0.14%, rounded down to 0.1% for the Barometer Group.

(3) Conclusion of growth from page 1 of Schedule 16.

PECO Energy Company
Indicated Common Equity Cost Rate Through Use
of the Capital Asset Pricing Model (1)

	Value Line Adjusted Beta	Company-Specific Risk Premium Based on Market Premium of 6.4% (2)	CAPM Result Including Risk-Free Rate of 6.8% (3)
PECO Energy Company	0.85	5.4 %	12.2 %
Barometer Group of Nine Electric Companies			
American Electric Power Co., Inc.	0.70	4.5 %	11.3 %
Boston Edison Company	0.70	4.5	11.3
CINergy Corporation	0.85	5.4	12.2
DQE, Inc.	0.75	4.8	11.6
DTE Energy Company	0.80	5.1	11.9
Entergy Corp.	0.75	4.8	11.6
GPU, Inc.	0.85	5.4	12.2
Illinova Corporation	0.95	6.1	12.9
PP&L Resources, Inc.	0.75	4.8	11.6
Average	0.79	5.0 %	11.8 %

See page 2 for notes.

PECO Energy Company
Development of the Market-Required Rate of Return on Common Equity Using the Capital Asset Pricing Model for PECO Energy Company and the Barometer Group of Nine Electric Companies
Adjusted to Reflect a Forecasted Risk-Free Rate and Market Return

Notes:

(1) The traditional Capital Asset Pricing Model (CAPM) is applied using the following formula:

$R_S = R_F + \beta\,(R_M - R_F)$

where R_S = Return rate of common stock
R_F = Risk Free Rate
β = Value Line Adjusted Beta
R_M = *Return on the market as a whole*

(2) From the six previous month-end (Sep. '96 - Feb. '97), as well as a recently available (Mar. 14, 1997), Value Line Summary & Index, a forecasted 3-5 year total annual market return of 12.2% can be derived by averaging the, 6-month, 3-month and spot forecasted total 3-5 year total appreciation, converting it into an annual market appreciation and adding the Value Line average forecasted annual dividend yield.

The 3-5 year average total market appreciation of 47%, produces a four-year average annual return of 10.11% (($1.47^{.25}$) - 1). When the average annual forecasted dividend yield of 2.08% is added, a total average market return of 12.19%, rounded to 12.2%, (2.08% + 10.11%) is derived.

The 6-month, 3-month and spot forecasted total market return of 12.2% minus the risk-free rate of *6.8% (forecasted 30-year Treasury Bond) is 5.4% (12.2% - 6.8%). The Ibbotson Associates calculated* market premium of 7.3% for the period 1926-1995 results from a total market return of 12.5% less the average income return on long-term U.S. Government Securities of 5.2% (12.5% - 5.2% = 7.3%). The 7.3% is then averaged with the 5.4% Value Line derived market premium resulting in a 6.35%, rounded to 6.4% market premium. The 6.4% market premium is then multiplied by the beta in column 1 of page 1 of this Schedule.

(3) The March 7, 1997 30-year Treasury Bond yield is assumed as the appropriate risk-free rate, particularly in light of a consensus forecasted 30-year Treasury Bond yield of about 6.8% as can be derived from the information shown on page 3 of Schedule 3.

Source of Information: Value Line Summary & Index
Value Line Investment Survey, January 10, and March 14, 1997
Federal Reserve Statistical Release, March 10, 1997
Stocks, Bonds, Bills and Inflation - 1996 Yearbook Market Results for 1926-1995 Ibbotson Associates, Inc., Chicago, IL

PECO ENERGY COMPANY
UPDATE OF "ELECTRIC AND TELEPHONE UTILITY STOCKHOLDER RETURNS: 1972-1992" (NARUC - SEPTEMBER 13, 1993)

LINE NO.		NARUC (1)		NARUC - Update (2)		
		OVERALL AVERAGE RETURN 1972 - 1992 (3)	TWENTY-ONE YEAR HOLDING PERIOD 1972 - 1992 (4)	TWENTY-FIVE YEAR HOLDING PERIOD 1972 - 1996 (5)	FIVE YEAR HOLDING PERIOD 1992 - 1996 (6)	SIX YEAR HOLDING PERIOD 1992 - 1997 (7)
1.	AVERAGE OF ALL UTILITIES	14.46 %	9.79 %	9.70 %	8.44 %	7.76 %
2.	AVERAGE OF ALL ELECTRIC UTILITIES	14.19 %	9.56 %	9.51 %	7.85 %	7.30 %
3.	AVERAGE OF ALL TELEPHONE UTILITIES	17.45 %	12.41 %	12.45 %	17.00 %	14.36 %
4.	PECO ENERGY CO.	13.87 %	8.31 %	8.38 %	9.18 %	6.68 %
5.	MAJOR NON-REGULATED U.S. INDUSTRIAL COMPANIES (8)	12.95 %	10.18 %	10.27 %	10.79 %	13.43 %
6.	PERCENT OF ALL ELECTRICAL AND TELEPHONE UTILITIES WHOSE RETURN IS GREATER THAN THAT OF MAJOR NON-REGULATED U.S. INDUSTRIAL CORPORATIONS (8)	72 %	43 %	33 %	32 %	8 %

See pages 2 and 3 of this Schedule for notes.

Source of Information: Electric and Telephone Utility Stockholder Returns: 1972-1992" (NARUC - September 13, 1993)
Standard & Poor's Compustat Services Inc., Utility and Telecommunications Compustat II
Standard & Poor's January and February 1997 Stock Guides
Standard & Poor's Statistical Service, Security Price Index Record, 1996 Edition
Standard & Poor's Statistical Service, Current Statistics, February 1997

PECO Energy Company
Update of "Electric and Telephone Utility Stockholder
Returns: 1972 - 1992" (NARUC - September 13, 1993)

Notes:

(1) From "Electric and Telephone Utility Stockholder Returns: 1972 - 1992" (NARUC - September 13, 1993), pp. 55-56, 85 and 100-101.

(2) Updated using identical methodology to that used in "Electric and Telephone Utility Stockholder Returns: 1972 - 1992" (NARUC - September 13, 1993) as described on pages 6-8 of the NARUC Study.

Data for 1972-1976 for the electric and telephone utilities were taken from the NARUC Study, pp. 41-42, 45, 47-48 and 51. Data for 1977-1997 for the electric and telephone utilities are from Standard & Poor's (S&P) Compustat Services Inc., Utility and Telecommunications Compustat II and the February 1997 S&P Stock Guide. Data for 1972-1997 for the S&P 400 Industrial Composite are from S&P Statistical Service, Security Price Index Record, 1996 Edition, pp. 131-133, S&P's Current Statistics, February 1997, p. 29, and S&P's January and February 1997 Stock Guides, p. 257. Data for 1972-1992 for the Value Line Industrial Composite are from the NARUC Study, pp. 45-46 and 51-52. Data for 1993-1996 for the Value Line Industrial Composite are from Value Line Investment Survey, Selection & Opinion, August 23, 1996, p. 7285.

Gulf States Utilities Co., Iowa-Illinois Gas & Electric Co., PSI Holdings, Inc. and Centel Corp. have been excluded from the update: Gulf States Utilities Co. is now Entergy Gulf States, a subsidiary of Entergy Corp.; Iowa-Illinois Gas & Electric Co. merged into MidAmerican Energy Holdings; PSI Holdings, Inc. is now a subsidiary of CINergy Corp.; and Centel Corp. is now a subsidiary of Sprint Corp.

(3) Average of 171 hypothetical holding periods.

(4) Average return for a single twenty-one year holding period assuming that a stock is purchased in mid-1972 and sold in mid-1992.

(5) Average return for a single twenty-five year holding period assuming that a stock is purchased in mid-1972 and sold in mid-1996.

(6) Average return for a single five year holding period assuming that a stock is purchased in mid-1992 and sold in mid-1996.

(7) Average return for a single six year holding period assuming that a stock is purchased in mid-1992 and sold in mid-1997.

PECO Energy Company
Update of "Electric and Telephone Utility Stockholder
Returns: 1972 - 1992" (NARUC - September 13, 1993)

(8) The NARUC study included the Value Line Industrial Composite but the percent of all electric and telephone utilities whose return is greater than that of major non-regulated U.S. industrial companies was relative to S&P 400 Industrial Composite. Thus, percentages shown on Lines No. 5 and 6 are for the S&P 400 Industrial Composite.

PECO ENERGY COMPANY

RETURN ON AVERAGE COMMON EQUITY FOR THE YEARS 1972-1992, 1972-1995, 1992-1995 AS REPORTED AND ADJUSTED TO EXCLUDE ALL AFUDC FOR ELECTRIC AND TELEPHONE UTILITIES USED IN "ELECTRIC AND TELEPHONE STOCKHOLDER RETURNS: 1972-1992" (NARUC - SEPTEMBER 13, 1993)

	1972-1992 RETURN ON AVERAGE COMMON EQUITY		1972-1995 RETURN ON AVERAGE COMMON EQUITY		1992-1995 RETURN ON AVERAGE COMMON EQUITY	
	AS REPORTED (1)	ADJUSTED TO EXCLUDE ALL AFUDC (2)	AS REPORTED (1)	ADJUSTED TO EXCLUDE ALL AFUDC (2)	AS REPORTED (1)	ADJUSTED TO EXCLUDE ALL AFUDC (2)
AVERAGE OF ALL UTILITIES (3)	12.44 %	9.03 %	12.30 %	9.25 %	11.31 %	10.76 %
AVERAGE OF ALL ELECTRIC UTILITIES	12.35 %	8.74 %	12.20 %	8.97 %	11.12 %	10.55 %
AVERAGE OF ALL TELEPHONE UTILITIES	13.86 %	12.96 %	13.86 %	13.05 %	14.04 %	13.83 %
PECO Energy Co.	11.11 %	4.25 %	11.20 %	5.12 %	11.51 %	10.95 %
EARNINGS/BOOK RATIO FOR MAJOR NON-REGULATED U.S. INDUSTRIAL COMPANIES (4)	14.33 %		15.10 %		18.65 %	

See page 2 of this Schedule for notes.

SOURCE OF INFORMATION: Standard & Poor's Compustat Services, Inc.
Utility Compustat II & Telecommunications Compustat II
S&P Security Price Index Record, 1996 Edition, pp. 2 and 128-133

PECO Energy Company
Return on Average Book Common Equity for the Years
1972 - 1992, 1972 - 1995 and 1992 - 1995
as Reported and Adjusted to Exclude All AFUDC
for the Electric and Telephone Utilities Included in the
"Electric and Telephone Utility Stockholder
Returns: 1972 - 1992" (NARUC - September 13, 1993)

Notes:

(1) *Calculated as income available for common stock divided by the average of the* beginning and ending year's total common equity.

(2) Calculated as income available for common stock less total Allowance for Funds Used During Construction (AFUDC) divided by the average of the beginning and ending year's total common equity.

(3) Gulf States Utilities Co., Iowa-Illinois Gas & Electric Co., PSI Holdings, Inc. and Centel Corp. have been excluded from the update: Gulf States Utilities Co. is now Entergy Gulf States, a subsidiary of Entergy Corp.; Iowa-Illinois Gas & Electric Co. merged into MidAmerican Energy Holdings; PSI Holdings, Inc. is now a subsidiary of CINergy Corp.; and Centel Corp. is now a subsidiary of Sprint Corp.

(4) Calculated as earnings per share for the Standard & Poor's (S&P) 400 Industrial Composite divided by the average of the beginning and ending year's book value per share. 1995 earnings / book for the S&P 400 Industrial Composite is based upon an estimated 1995 book value per share for the Composite.

PECO Energy Company
Comparison of Income Available for Common Equity: Based Upon Authorized Return Rate on Common Equity Applicable to Electric Operations and as Reported - Including and Excluding all AFUDC

	1	2	3	4	5	6	7
	Income Available for Common Equity						
Year	as Reported (1) ($ mill)	Excluding All AFUDC (2) ($ mill)	Authorized Return Rate on on Common Equity Applicable to Electric Operations (3) (%)	Average Common Equity (4) ($ mill)	Income Available for Common *Based Upon* Auth. Return on Common Equity (5) ($ mill)	Income Avail. for Common Equity as Reported less Income Avail. for Common Equity *Based Upon* Auth. Return on Common Equity (6) ($ mill)	Income Avail. for Common Equity Excl. all AFUDC less Income Avail. for Common Equity *Based Upon* Auth. Return on Common Equity (7) ($ mill)
1972	$85.928	$43.478	10.00 %	$838.211	$83.821	$2.107	($40.343)
1973	94.811	36.068	10.20	975.734	99.525	(4.714)	(63.457)
1974	94.825	23.984	10.20	1,067.329	108.868	(14.043)	(84.884)
1975	107.902	41.028	11.00	1,148.990	126.389	(18.487)	(85.361)
1976	125.204	47.563	11.00	1,272.637	139.99	(14.786)	(92.427)
1977	132.734	46.656	11.00	1,379.973	151.797	(19.063)	(105.141)
1978	141.349	50.352	13.50	1,455.025	196.428	(55.079)	(146.076)
1979	149.698	36.315	13.50	1,526.426	206.068	(56.370)	(169.753)
1980	174.950	27.400	14.00	1,655.595	231.783	(56.833)	(204.383)
1981	223.761	34.964	15.45	1,847.356	285.417	(61.656)	(250.453)
1982	278.623	65.363	17.02	2,107.767	358.742	(80.119)	(293.379)
1983	321.705	45.711	17.58	2,410.665	423.795	(102.090)	(378.084)
1984	409.707	54.852	16.15	2,728.935	440.723	(31.016)	(385.871)
1985	434.724	1.233	16.70	3,040.797	507.813	(73.089)	(506.580)
1986	474.693	296.255	15.75	3,342.250	526.404	(51.711)	(230.149)
1987	446.450	277.067	14.75	3,439.170	507.278	(60.828)	(230.211)
1988	468.765	247.694	14.75	3,488.513	514.556	(45.791)	(266.862)
1989	493.807	223.307	14.75	3,667.442	540.948	(47.141)	(317.641)
1990	15.458	(39.877)	13.42	3,683.425	494.316	(478.858)	(534.193)
1991	468.576	445.492	12.75	3,757.192	479.042	(10.466)	(33.550)
1992	418.210	397.547	12.75	3,956.010	504.391	(86.181)	(106.844)
1993	541.590	517.816	12.75	4,141.579	528.051	13.539	(10.235)
1994	389.415	367.246	12.75	4,281.719	545.919	(156.504)	(178.673)
1995	586.515	559.465	12.75	4,415.627	562.992	23.523	(3.527)
1996	499.169	479.222	12.75	4,587.337	584.885	(85.716)	(105.663)
Cumulative	$7,578.569	$4,326.201			$9,149.941	($1,571.372)	($4,823.740)

Notes:
(1) Calculated as income available for common stock divided by the average of the beginning and ending year's total common equity.
(2) Calculated as income available for common stock less total Allowance for Funds Used During Construction (AFUDC) divided by the average of the beginning and ending year's total common equity.
(3) Company-provided.
(4) Average of beginning and ending year's total common equity.
(5) Column 3 x column 4.
(6) Column 1 - column 5.
(7) Column 2 - column 5.

Source of Information: Standard & Poor's Compustat Services, Inc., Utility Compustat II
Moody's Public Utility Manuals
PECO Energy Company 1996 Annual Report to Shareholders
Company-provided data

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