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E. Holbert

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 1  
VOLUME V

Contents:

- Statement No. 9 - Direct Testimony & Exhibits of James I. Warren
- Statement No. 10 - Direct Testimony & Exhibits of Gregory Sidak
- Statement No. 11 - Direct Testimony & Exhibits of Joseph F. Brennan

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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

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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1 DIRECT TESTIMONY OF JAMES I. WARREN

2 I. QUALIFICATIONS

3  
4 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

7  
8 Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

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

10  
11 Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES AT REID &  
12 PRIEST AND YOUR PROFESSIONAL AND EDUCATIONAL  
13 BACKGROUND.  
14

15 A. A description of my responsibilities and my professional and educational  
16 background is appended as Exhibit JIW-1.  
17

18 II. INTRODUCTION AND SUMMARY

19  
20 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

21 A. The purpose of my testimony is to describe and explain the principles which  
22 govern PECO Energy Company's ("PECO" or the "Company") treatment of: (1)  
23 accumulated deferred federal income taxes ("ADFIT"), (2) regulatory assets and  
24 liabilities associated with accounting for income taxes under FAS 109 ("FAS 109  
25 assets and liabilities") and (3) accumulated deferred investment tax credits  
26 ("ADITC") in its quantification of its stranded costs. I shall then discuss the way

1 in which those principles are reflected in the Company's filing. I shall address  
2 these areas primarily on a conceptual basis. Mr. Alan Cohn's testimony will  
3 describe the particulars of the Company's filing in significantly greater detail.  
4

5  
6 **Q. WILL YOU SUMMARIZE YOUR TESTIMONY?**

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

1 **III. ADFIT AND FAS 109 ASSETS AND LIABILITIES**

2  
3  
4 **Q. WHAT ARE THE FUNDAMENTAL PRINCIPLES THAT GOVERN THE**  
5 **TREATMENT OF ADFIT AND FAS 109 ASSETS AND LIABILITIES?**

6  
7 A. There are two principles of fundamental importance. The first has to do with the  
8 way in which federal income taxes impact the ratemaking process and the second  
9 with the nature of deferred taxes.

10  
11  
12 **Q. PLEASE STATE THE FIRST PRINCIPLE?**

13  
14 A. The first principle is that, in our 35% federal income tax rate environment, in  
15 order to fund \$1 of federal income tax expense, PECO must receive revenues of  
16 approximately \$1.54. This is because PECO's revenues are fully taxable and,  
17 unlike the situation with salary, fuel and most other expenses incurred by PECO,  
18 federal income taxes are not deductible. Thus, there is no deduction to offset the  
19 taxable revenue. After receiving \$1.54 of revenue and paying a \$.54 federal  
20 income tax on this receipt, PECO will have \$1 left with which to pay its tax.

21  
22 **Q. IS THIS SITUATION PECULIAR TO PECO OR TO PUBLIC UTILITIES**  
23 **IN GENERAL?**

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

27  
28 **Q. DOES IT MATTER WHETHER THE TAX EXPENSE IS CURRENTLY**  
29 **PAYABLE OR PAYABLE IN THE FUTURE?**

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

7  
8 **Q. DOES THE AMOUNT OF REVENUE NEEDED TO FUND A GIVEN**  
9 **LEVEL OF TAX DEPEND AT ALL ON WHETHER THE COMPANY**  
10 **PRACTICES NORMALIZATION OR FLOW THROUGH RATEMAKING?**

11  
12 A. No. The difference between normalization and flow through ratemaking relates  
13 only to *when* a given level of tax expense will be funded through the rate  
14 process, not to *how much* must be received to fund the tax. Thus, the  
15 ratemaking method employed is entirely irrelevant to the "gross up" principle set  
16 forth above. If normalization is practiced, the Company may charge the \$1.54 in  
17 advance of its payment of the \$1 tax to the government. If flow through is  
18 practiced, then the \$1.54 will be charged only contemporaneously with the \$1 tax  
19 payment to the government. In either case, the customers must be charged the  
20 same amount (\$1.54) to fund the same level of tax (\$1).

21  
22  
23 **Q. WHAT IS THE SECOND PRINCIPLE?**

24 A. The second principle is that a deferred federal income tax constitutes the  
25 economic equivalent of an interest-free loan from the federal government. This is

1 most clearly illustrated by examining the operation of accelerated tax  
2 depreciation, the item which generally produces most deferred taxes. With  
3 respect to any depreciable asset, a loan is extended as the Company claims tax  
4 depreciation which exceeds its book (*i.e.*, economic) depreciation. This  
5 generally occurs as the Company claims accelerated tax depreciation on its tax  
6 return in the early years of the asset's productive life. The loan is "repaid" as the  
7 Company's book depreciation exceeds its tax depreciation. Deferred taxes  
8 therefore represent the necessity to pay an amount to the government in the  
9 future.

10  
11 **Q. DOES THE EXISTENCE OF THE LOAN DEPEND ON WHETHER THE**  
12 **COMPANY PRACTICES NORMALIZATION OR FLOW THROUGH**  
13 **RATEMAKING?**

14  
15 A. No. The interest-free loan is extended to the Company as it claims accelerated  
16 depreciation on its tax return. It is in no way dependent on the ratemaking  
17 process. General Motors, IBM and most other American enterprises, regulated  
18 or not, receive loans of this type. The availability of the loan is a matter  
19 between the company and the government. The ratemaking process only impacts  
20 the timing of the receipt by the utility of the wherewithal to repay the loan.

21  
22 **Q. HOW IS THIS REFLECTED IF THE COMPANY'S REGULATORS**  
23 **PERMIT NORMALIZED RATEMAKING?**

24  
25 A. If the Company's regulators permit normalized ratemaking, it retains the  
26 governmental loan proceeds and is, therefore, responsible for its eventual

1 repayment out of its own resources. The reflection of this obligation takes the  
2 form of a deferred tax credit. To follow through the simple example, the  
3 Company would receive \$1.54 in rates for each \$1 of its tax expense, including  
4 its deferred tax expense. It would pay \$.54 in tax on the receipt of this amount  
5 and record a \$1 deferred tax. The \$1 could then be used in its business  
6 operations until such time as it was required to be paid back to the government.  
7

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

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

22  
23 **Q. HOW DOES FAS 109 REQUIRE THE COMPANY TO REFLECT THE**  
24 **FLOW THROUGH SITUATION?**  
25

1

2

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.

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

14

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.

15

16

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

25

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

1 effect of the lower revenues by recording as a regulatory asset the promise on the  
2 part of regulators to increase rates at a later date to "flow back" the amount. This  
3 obligation assumes the form of a FAS 109 asset. It is the recordation of this  
4 promise that reflects the opportunity afforded the utility to earn its allowed rate of  
5 return even though one of its economic costs, deferred taxes, is not being  
6 currently funded. Thus, a regulated enterprise can defer the collection of its  
7 \$1.54 for each \$1 of deferred tax in the year the governmental loan is extended  
8 until a later time without negatively impacting earnings.

9  
10 Non-regulated enterprises have no such flexibility. They are unable to establish  
11 the regulatory FAS 109 assets which utilities can establish. As a consequence, if  
12 a non-regulated enterprise "flows through" the proceeds of a governmental loan  
13 to its customers in the year it is extended, its net income is diminished. It has not  
14 covered its economic costs (*i.e.*, deferred taxes) - even if it has covered its cash  
15 costs (*i.e.*, currently payable taxes). Thus, utilities are unique in the flexibility  
16 the accounting rules afford their treatment of tax expense.

17  
18 **Q. WILL YOU PROVIDE A SIMPLE EXAMPLE OF HOW THESE TWO**  
19 **PRINCIPLES INTERACT WITH ONE ANOTHER?**

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

1 and a 2 year tax life. U's governmental loan posture looks as follows:

2

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

3  
4 As the matrix above indicates, U borrows from the government in the first two  
5 years (\$35 each year) and repays the aggregate loan (\$70) in the third year.

6  
7 **Q. DOES THE EXTENSION OF THE LOAN HAVE ANYTHING**  
8 **WHATSOEVER TO DO WITH THE RATEMAKING PROCESS?**  
9

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

13  
14 **Q. OF WHAT RELEVANCE IS RATEMAKING, THEN?**

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

1 the examples which follow.

2  
3 **Q. HOW WOULD RATES BE SET UNDER THESE CIRCUMSTANCES IF**  
4 **U'S REGULATORS PERMIT NORMALIZED RATEMAKING?**  
5

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

12	Revenues	\$1,154
13	Expenses	(800)
14	Book Depreciation	<u>(200)</u>
15	Pre-tax Income	\$154
16	Tax Expense (35%)	<u>(54)</u>
17	Net Income	<u>\$100</u>

18  
19 **Q. WHAT WILL U'S TAX RETURN LOOK LIKE?**

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

21	Revenues	\$1,154
22	Expenses	(800)
23	Tax Depreciation	<u>(300)</u>
24	Taxable Income	\$54
25	Tax Return Tax (35%)	\$19

26 U has a currently payable tax liability of \$19. The difference between this

1 amount and U's total tax expense of \$54 is its deferred tax liability of \$35. This  
2 is the amount of the governmental loan extended in each of those years by virtue  
3 of being able to claim \$100 more tax depreciation than economic depreciation.  
4

5 **Q. UNDER NORMALIZATION RATEMAKING, WHAT HAPPENS TO THE**  
6 **LOAN PROCEEDS?**  
7

8 A. Under normalization ratemaking, U retains the loan proceeds and can use this  
9 amount to finance its operations. The existence of this zero-cost loan would be  
10 recognized in the ratemaking process. Deferred tax balances are employed to  
11 reduce regulated rate base. Thus, customers are not charged a return on rate base  
12 which is financed by these governmental loans. In this way, the full financial  
13 benefit of the zero-cost loans is provided to customers.  
14

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

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

22	Revenues	\$1,100
23	Expenses	(800)
24	Tax Depreciation	<u>(300)</u>
25	Taxable Income	\$0
26	Tax Return Tax	\$0

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

2	Revenues	\$1,100
3	Expenses	(800)
4	Book Depreciation	<u>(200)</u>
5	Pre-tax Income	\$100
6	Tax Return Tax	<u>(0)</u>
7	Net Income	<u>\$100</u>

8 Note that flow through rates (*i.e.*, revenues) are less than normalized rates by  
9 \$54. This reduction represents the rate effect of "flowing through" the benefit of  
10 the \$35 governmental loan. The amount of the loan is "grossed up" as previously  
11 described. However, the loan still exists, notwithstanding the fact that its benefit  
12 was "flowed through" to customers and U is still responsible for its repayment.  
13 FAS 109 reflects this by requiring U to reflect the \$35 governmental loan as a  
14 deferred tax. However, FAS 71 also permits U to reflect a FAS 109 asset for the  
15 \$54 the customers will pay back to the company when the loan becomes due.  
16 Finally, U must reflect as an incremental deferred tax the income tax it will be  
17 assessed upon the receipt of that \$54 ( $\$54 \times 35\%$  or \$19).

18  
19 At the end of Year 2, the governmental loan portion of U's deferred tax balance  
20 will equal \$70. Its FAS 109 asset balance, the future revenue necessary to fund  
21 the loan repayment, will equal \$108. Finally, U will reflect as an additional  
22 deferred tax liability the \$38 tax cost of receiving the future revenue.

23  
24 **Q. WHAT HAPPENS IN THE FLOW THROUGH SITUATION IN YEAR 3?**

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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	<u>(0)</u>
Taxable Income	\$462
Tax Return Tax (35%)	\$162

U's financial statement would appear as follows:

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

**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.

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**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,

1 as it must, a "tax gross up" so that the Company will have the wherewithal to pay  
2 the amount due the government.

3  
4 As described above, the Company's "creditor" is the government and its "debtor"  
5 is its customers. Thus, the debtor and creditor are not the same. This is not a  
6 situation where the Company is owed money by someone to whom it owes  
7 money. Thus, the liability and the receivable cannot be rationally netted. The  
8 situation is analogous to that of an employee who has a mortgage on his house  
9 and who is owed a week's wages by his employer. Notwithstanding that the  
10 wages will be used to pay down the mortgage (after the payment of income  
11 taxes), there is no conceivable way that the employer should be permitted to  
12 reduce its obligation to the employee due to the existence of the mortgage  
13 obligation. No rational person could support such a proposition. So it is with the  
14 Company's FAS 109 assets. These represent the source from which the  
15 governmental loans will be repaid. No netting is supportable.

16  
17 **Q. WHY IS THE FAS 109 ASSET BALANCE COMPUTED ON A "GROSSED**  
18 **UP" BASIS WHILE THE ADFIT BALANCE IS NOT?**

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

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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.

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

10  
11  
12 **Q. WHAT ARE THE VARIOUS ELEMENTS OF SUCH TIME VALUE**  
13 **BENEFITS?**  
14

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

18  
19 **Q. WHAT IS THE NATURE OF THE BENEFIT OF LOANS CURRENTLY IN**  
20 **PLACE?**

21 A. The Company has a substantial existing balance of deferred taxes associated with  
22 its stranded investment. However, these balances will inexorably diminish.  
23 Once stranded costs become incorporated into the CTC, it is the amortization  
24 period of the CTC, and not the original depreciable life of the underlying assets,  
25 that governs the triggering of the necessity to repay the loan. In this regard, the

1 effect is not unlike shortening an asset's depreciable life. Thus, whatever loans  
2 are currently outstanding will diminish over the CTC amortization period. At the  
3 end of that time, they will be extinguished. Thus, the value of the loans currently  
4 in place is equal to the present value of the use of an amount of cost-free capital  
5 that diminishes over the CTC amortization period.

6  
7 **Q. WHAT IS THE NATURE OF THE BENEFIT OF LOANS NOT YET**  
8 **EXTENDED?**

9  
10 A. The Company's stranded investment has significantly less tax basis than book  
11 basis (much, but not all, of the difference due to accelerated tax depreciation).  
12 However, these assets still retain a rather substantial amount of tax basis. This  
13 stranded investment tax basis will produce a stream of tax deductions in the future  
14 (*e.g.*, future accelerated depreciation claimed with respect to generating plant).  
15 These future deductions will produce at least some governmental loans similar to  
16 the ones already in place (which are evidenced by existing deferred tax balances).  
17 The net benefit of the use of the cost free capital during the time between the  
18 future extension of the governmental loans and their repayment must be valued  
19 and then reflected in the amounts customers are required to pay.

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

21  
22 A. The Company has captured both of the time value benefits described above. The  
23 aggregate net present value of these benefits has been used to reduce the return  
24 required with respect to the stranded investment. By means of this mechanism,  
25 the Company's customers have been provided the full, true economic value of the

1 availability of all present and future loans.

2  
3 IV. ADITC

4  
5  
6 **Q. WILL YOU DESCRIBE HOW THE COMPANY HAS TRADITIONALLY**  
7 **ACCOUNTED FOR ITS INVESTMENT TAX CREDITS (THE "CREDIT")?**  
8

9 A. Up until the end of 1985, the tax law awarded tax credits to taxpayers making  
10 enumerated types of investments. Over the years, the Company became entitled  
11 to these credits as a result of certain of its plant investments. The Company was  
12 able to use the credits earned to reduce the tax liability otherwise due. In the  
13 year in which a credit was used to reduce its currently payable tax, the Company  
14 did not reduce tax expense immediately. Instead, it recorded a deferred credit  
15 *which had the effect of deferring the income statement benefit of credit*  
16 *utilization.* It amortized the deferred credit as a reduction to the tax expense  
17 *element of cost of service over the regulatory life of the asset producing the credit*  
18 *(as the asset was depreciated).* Thus, customers received the benefit of the credit  
19 *as they funded the asset over its life.*  
20  
21  
22

23 **Q. WHAT DOES THE ADITC BALANCE REPRESENT AND HOW IS IT**  
24 **TREATED IN RATEMAKING?**  
25

26 A. The ADITC balance consists of the amount of credits claimed on tax returns

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

12  
13 **Q. WHY HAS THE COMPANY ADOPTED THIS RATEMAKING**  
14 **APPROACH?**

15  
16 A. As a condition to accessing the benefit of the credit, the Internal Revenue Code  
17 ("Code") requires that a regulated public utility share the benefit of the credit  
18 between customers and shareholders. The rules that compel this are referred to  
19 as the Credit Normalization Rules. The Company's approach represents one of  
20 the two sharing mechanisms permitted by the Code.

21  
22 **Q. WHAT WOULD OCCUR IF THE CREDIT NORMALIZATION RULES**  
23 **WERE NOT COMPLIED WITH?**

24  
25 A. A failure to comply with the sharing requirement over the entire life of the asset  
26 will result in a recapture (*i.e.*, a repayment to the government) of the entire

1 unamortized ADITC balance associated with all jurisdictional assets (not just the  
2 ADITC which is not properly shared).

3  
4 **Q. HOW HAS THE COMPANY DEALT WITH THE ADITC WHICH**  
5 **RELATES TO STRANDED GENERATING PLANT?**

6  
7 A. The Company has used this balance to offset the CTC charge, but only after  
8 discounting the amount. The discounting has the effect of providing to  
9 shareholders the time value of the ADITC balance. In effect, it provides to them  
10 something like the return they would have earned had the stranded investment  
11 remained in a rate base environment.

12  
13 **Q. WHY HAS THE COMPANY ADOPTED THIS APPROACH?**

14 A. The Company has adopted this approach for two reasons. First and most  
15 significantly, this approach is consistent with a basic principle which has guided  
16 the Company in the formulation of its proposal regarding the treatment of taxes in  
17 this proceeding. In crafting its approach, the Company has used a "no harm, no  
18 foul" philosophy. It believed, and continues to believe, that the treatment of all  
19 parties should be consistent with historical treatment of each. This is evidenced  
20 by the careful attempt the Company has made to provide to customers the entire  
21 time value benefit of all deferred taxes - both present and future - associated with  
22 stranded investments. This is appropriate because the time value benefit is one  
23 customers have historically enjoyed. The Company has historically received a  
24 return benefit from its ADITC. To deprive it of this benefit in this proceeding

1 would amount to "cherry picking" - carrying through the effects of those  
2 procedures that have historically benefitted the customers (e.g., ADFIT time  
3 value benefits) but not those that have historically benefitted the Company. This  
4 is simply unfair.

5  
6 **Q. WHAT IS THE SECOND REASON FOR DISCOUNTING THE ADITC?**

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

11  
12 **Q. WILL YOU ELABORATE ON WHY YOU BELIEVE THIS RISK EXISTS?**

13  
14 A. There are two possible ways in which the IRS might view the treatment of  
15 stranded investment in this case from a Credit Normalization Rule perspective. It  
16 is possible that the IRS would take the view that the result of this proceeding is  
17 merely the designation of a level of stranded cost recovery and that such  
18 designation is beyond the purview of the Credit Normalization Rules because it  
19 has nothing to do with the benefits of credits claimed with respect to depreciable  
20 utility property. However, it is also possible that the IRS will view the  
21 computation of the CTC charge as merely the identification of specific costs  
22 (some of which have ADITC associated with them) to be recovered in a  
23 specifically designated fashion - through an CTC charge. In effect, a portion of  
24 the CTC may well be considered as utility plant costs which have been given

1 another name and assigned a new life different from that of non-stranded plant  
2 costs. Under this view, because the underlying costs remain, the sharing  
3 requirement of the normalization rules would remain operative.  
4

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

7 A. Yes it is.  
8

9 **Q. ON WHAT DO YOU BASE THIS OPINION?**

10 A. I base my opinion on two factors.  
11

12 **Q. WILL YOU DESCRIBE THE FIRST FACTOR.**

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

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

2 Unlike the situation when public utility property is sold  
3 outright, in the sale-leaseback transaction the Utilities and  
4 their ratepayers continue to bear the cost of the property  
5 over the lease term. The regulated depreciation expense is  
6 simply replaced by a regulated rental expense. This is a  
7 critical factor in a determination of the proper treatment of  
8 the unamortized credits after the sale-leaseback transaction.  
9

10 It concluded, therefore, that the utility's ADITC which related to the plant should  
11 be amortized by the utility over a period no shorter than the life of the lease.  
12

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

15  
16 A. In the ruling, the National Office concluded that the lease payments after the  
17 transaction were economically equivalent to the regulatory depreciation it had  
18 claimed with respect to the same plant before the transaction. If this "economic  
19 equivalence" rationale were applied to the current situation, it could support a  
20 continuation of the relevance of the Credit Normalization Rules.  
21

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

24 A. A ruling such as the one described above is not precedential and is, therefore, not  
25 binding on the IRS (except with regard to the taxpayer to whom the ruling was  
26 issued). However, in the area of the application of the Credit Normalization  
27 Rules, there are very few authorities which enable practitioners to definitively  
28 ascertain the consequences of these rules for the many novel and creative

1 regulatory proposals which have become prevalent. Thus, practitioners in the  
2 area routinely attempt to identify the rationales and approaches used by the IRS in  
3 such rulings to ascertain potential IRS positions in analogous situations. Even  
4 though non-precedential, these rulings serve as an important, if not actually the  
5 major, source of input regarding the application off the Credit Normalization  
6 Rules.

7  
8 **Q. WILL YOU DESCRIBE THE SECOND FACTOR SUPPORTING YOUR**  
9 **CONCLUSION?**

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

1 Q. **BASED ON THE ABOVE, WILL YOU RESTATE YOUR CONCLUSION**  
2 **REGARDING THE APPLICATION OF THE CREDIT NORMALIZATION**  
3 **RULES TO PECO'S SITUATION?**  
4

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

9

10

#### V. CONCLUSION

11

12 Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

13 A. Yes, it does.

14

**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:

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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(1) 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(1)(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(1)-1(h)(2) of

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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 SIDAŁ**

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

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**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**

1 Q. Please state your name and business address.

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

4

5

**PURPOSE AND SCOPE OF TESTIMONY**

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

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

17

18

**CONCLUSION**

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

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

10  
11 My analysis of the economic objectives and historical origins of public utility regulation  
12 is focused on what it means for utilities and regulators mutually to have considered  
13 investments to be “traditionally recoverable under a regulated environment.” First, I  
14 show that historical evidence substantiates the existence of a “regulatory contract” and  
15 that compelling economic arguments confirm the need for such a contract between the  
16 electric utility and the state. To phrase matters in terms of the Act, there is a powerful  
17 economic argument that a Pennsylvania utility expected, under traditional regulatory  
18 practice, to receive a reasonable opportunity to earn revenues sufficient to recover its  
19 prudently incurred investments and a competitive return on those investments.  
20 Pennsylvania would breach the regulatory contract if it were to order retail wheeling  
21 without allowing the incumbent utility (that is, PECO Energy) to achieve full recovery  
22 of the stranded costs of its prudently incurred investments. Second, I show that  
23 Pennsylvania's failure to allow PECO Energy that opportunity would also effect a  
24 taking of property under the Fifth Amendment of the U.S. Constitution.

25  
26 **I. THE REGULATORY CONTRACT**

**A. Definitions**

1  
2 Q. **What is the “regulatory contract”?**

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

18

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

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

6  
7 Under current law and regulation there exists some competition in the  
8 wholesale market for the generation of electricity; but the generation,  
9 transmission, distribution and retail sale of electricity is provided  
10 generally by public utilities under bundled rates regulated by the  
11 Commission. The procedures established under this chapter provide for  
12 a fair and orderly transition from the current regulated structure to a  
13 structure under which retail customers will have direct access to a  
14 competitive market for the generation and sale or purchase of  
15 electricity.

16  
17 Moreover, as the preceding passage indicates, electric utilities in Pennsylvania have  
18 been subject to "rates regulated by the Commission." Finally, the Legislature notes, in  
19 section 2802(15), that electric utilities in Pennsylvania undertook obligations to serve  
20 and detrimentally relied upon the preexisting regulatory framework:

21  
22 . . . heretofore, public utilities generally have had an obligation to serve  
23 customers within their defined service territories; consistent with that  
24 obligation, have undertaken long-term investments in generation,  
25 transmission and distribution facilities in order to meet the needs of  
26 their customers; and have entered into long-term power supply

1                   agreements as required by federal law.

2

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

6

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

12

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

16

17       **Q.    How do “incumbent burdens” affect the regulatory contract?**

18       **A.**    When the state maintains regulatory obligations while it simultaneously eases entry  
19                  restrictions, incumbent utilities encounter costly competitive disadvantages, known as  
20                  “incumbent burdens.” Regulators typically require the public utility to provide universal  
21                  service at a fixed price, regardless of the true cost of service, and to act as the carrier of  
22                  last resort. In addition, regulation denies the utility the pricing flexibility of the entrant,  
23                  which places the utility at a competitive disadvantage. New entrants into regulated  
24                  markets, of course, first target those customers whom regulators require the regulated  
25                  incumbent to charge prices exceeding cost so that other customers may be charged  
26                  prices below cost. When the state deregulates entry, it will jeopardize the incumbent

1 utility's financial solvency unless the costs of incumbent burdens are either shared by all  
2 firms in the market or explicitly reimbursed by some third party. It is easy to cheer the  
3 arrival of competition to industries where it previously has been regulated or forbidden  
4 by law. But the predictable appeal that competition holds for legislators and regulators  
5 should not obscure the fact that the transition from regulated monopoly to competition  
6 is not free. Unless accompanied by other reforms, the advent of retail wheeling will  
7 preclude the recovery, through market-determined prices, of two sets of costs: the  
8 historical costs that the electric utility incurred to discharge its obligation to serve, and  
9 the future costs that incumbent burdens continue to impose on that incumbent utility.

10

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

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

18

19 Q. **What are stranded costs?**

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

1 by regulators, that the utility incurred in meeting its obligations to serve all customers in  
2 its service territory.

3  
4 **Q. Does the Electricity Generation Customer Choice and Competition Act recognize  
5 the existence of stranded costs in Pennsylvania?**

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

15  
16 **B. Historical Origins of the Regulatory Contract**

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

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

<sup>1</sup>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

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

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

18  
19 **Q. Do court decisions provide historical evidence of the existence of the regulatory**  
20 **contract?**

21 **A.** Yes. Numerous Supreme Court decisions confirm the understanding that the public  
22 utility entered into a contract with the state or municipal government. For example, in  
23 *The Binghamton Bridge*, 70 U.S. (3 Wall.) 51, 73 (1865), the Supreme Court stated:  
24

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

8  
9           Similarly, in *New Orleans Water-Works Co. v. Rivers*, 115 U.S. 674, 681 (1885), the  
10          Court said a utility's franchise to operate a waterworks

11  
12          was a contract, the obligation of which cannot be impaired by  
13          subsequent legislation, or by a change in her organic law. It is as much  
14          a contract, within the meaning of the Constitution of the United States,  
15          as a grant to a private corporation for a valuable consideration, or in  
16          consideration of public services to be rendered by it, of the exclusive  
17          right to construct and maintain a railroad within certain lines and  
18          between given points, or a bridge over a navigable stream within a  
19          prescribed distance above and below a designated point.

20  
21          *Accord, New Orleans Gas Co. v. Louisiana Light Co.*, 115 U.S. 650, 661 (1885). In  
22          *Walla Walla City v. Walla Walla Water Co.*, 172 U.S. 1, 8-9 (1898), the Court stated:

23  
24          [T]his court has too often decided for the rule to be now questioned,  
25          that the grant of a right to supply gas or water to a municipality and its  
26          inhabitants through pipes and mains laid in the streets, upon condition

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

6  
7 The Supreme Court well recognized by the turn of the century that key provisions in  
8 the regulatory contract existed to ensure cost recovery for specialized investments and  
9 to deter opportunism. In 1898 it observed: "It is not to be supposed that the company  
10 would have entered upon this large undertaking in view of the possibility that, in one of  
11 the sudden changes of public opinion to which all municipalities are more or less  
12 subject, the city might . . . practically extinguish the rights it had already granted to the  
13 company." *Walla Walla*, 172 U.S. at 17–18. In 1902, the Court similarly observed: "It  
14 would hardly be credible that capitalists about to invest money in what was then a  
15 somewhat uncertain venture, . . . would at the same time . . . give the right to the  
16 [municipality] to change at its pleasure from time to time those important and  
17 fundamental rights affecting the very existence and financial success of the company . .  
18 . ." *Detroit v. Detroit Citizens' Street Railway Co.*, 184 U.S. 368, 385 (1902).

### 19 20 **C. The Economic Rationale for the Regulatory Contract**

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

22 **A.** Yes. Economic analysis reinforces the conclusion drawn from historical analysis that  
23 the regulatory contract was necessary to address cost recovery, asset specificity,  
24 opportunism, and credible commitments. Consumers and businesses voluntarily  
25 participate in a market transaction only if they receive *gains from trade*—only if the  
26 transaction yields positive net benefits for them. A supplier will not invest in a

1 transaction unless the supplier expects the returns from the transaction to cover all  
2 economic costs, including a competitive return to invested capital. That principle is  
3 summarized in Professor Armen Alchian's classic definition of cost: "In economics, the  
4 cost of an event is the highest-valued opportunity necessarily forsaken." Armen A.  
5 Alchian, *Cost*, in 3 INTERNATIONAL ENCYCLOPEDIA OF THE SOCIAL SCIENCES 404, 404  
6 (David L. Sills ed., MacMillan Co. & Free Press 1968). The supplier's costs of  
7 investing in the transaction include the highest net benefit of all opportunities forgone,  
8 known as *opportunity cost*.

9  
10 **Q. What is the significance of transaction-specific investment to the regulatory**  
11 **contract?**

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

19  
20 [T]here is an important difference between regulated and unregulated  
21 markets. Unregulated firms bear the risk of stranded costs but are  
22 entitled to high profits if things go unexpectedly well. In contrast,  
23 utilities have been limited to regulated rates, intended to yield no more  
24 than a fair return on their investments. If competition were  
25 unexpectedly allowed, utilities would be exposed to low returns  
26 without having had the chance to reap the full expected returns in good

1 times, thus denying them the return promised to induce the initial  
2 investment. A strong case therefore can be made for allowing utilities  
3 to recover stranded costs . . . .  
4

5 1996 ECONOMIC REPORT OF THE PRESIDENT 817 (emphasis added). Professor Daniel  
6 Spulber of Northwestern University has made a similar point: “The regulatory contract  
7 is often justified as a means of mitigating the risks of making large irreversible invest-  
8 ments that are faced by regulated utilities.” DANIEL F. SPULBER, REGULATION AND  
9 MARKETS 610 (MIT Press 1989). “Customers of utilities gain from such commitments,  
10 since efficient levels of investment yield lower costs of service. There is an incentive to  
11 honor commitments regarding compensatory rates of return to assure that regulated  
12 firms will undertake future investment and that they will maintain their existing capital  
13 equipment.” *Id.* See also Glenn Blackmon & Richard Zeckhauser, *Fragile*  
14 *Commitments and the Regulatory Process*, 9 YALE J. ON REG. 73, 76–78 (1992).

15 Cost-of-service regulation of public utilities is based on allowing a utility the  
16 opportunity to recover its investment, including a competitive rate of return. “In the  
17 absence of a detailed long-term contract,” note Professors Laffont and Tirole, “the  
18 regulated firm may refrain from investing in the fear that once the investment is in  
19 place, the regulator would pay only for variable cost and would not allow the firm to  
20 recoup its sunk cost.” JEAN-JACQUES LAFFONT & JEAN TIROLE, A THEORY OF  
21 INCENTIVES IN PROCUREMENT AND REGULATION 54 (MIT Press 1993). Utilities have  
22 had to undertake substantial investments to discharge their obligation to serve. Indeed,  
23 as discussed previously, section 2802(15) of the Act itself confirms this fact, as it  
24 recognizes both that Pennsylvania “public utilities generally have had an obligation to  
25 serve customers within their defined service territories,” and that, “*consistent with that*  
26 *obligation,*” utilities “have undertaken long-term investments in generation,

1 transmission and distribution facilities in order to meet the needs of their customers.”  
2 (emphasis added). The purpose of a regulatory contract is to provide for recovery of  
3 “economic costs,” by which I mean the full cost of an activity, including direct  
4 expenditures, the time cost of money expended for capital investment, and any other  
5 opportunity costs.

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

15  
16 **Q. What is the significance of regulatory opportunism and asset specificity to the**  
17 **regulatory contract?**

18 A. The noted economist Oliver Williamson defines *opportunism* as “self-interest seeking with  
19 guile.” OLIVER E. WILLIAMSON, THE ECONOMIC INSTITUTIONS OF CAPITALISM: FIRMS,  
20 MARKETS, RELATIONAL CONTRACTING 47 (Free Press 1985). He describes utility  
21 regulation as a “highly incomplete form of long-term contracting” in which the terms are  
22 adapted to “changing circumstances” to assure the supplier of a fair rate of return. Oliver  
23 E. Williamson, *Franchise Bidding for Natural Monopolies—in General and with Respect*  
24 *to CATV*, 7 BELL J. ECON. 73, 91 (1976). The problem of regulatory opportunism stems  
25 from the fact that stranded investments and regulatory assets, including expenditures for  
26 plant and equipment and capitalized expenditures to perform duties mandated by

1 regulators, are likely to be transaction-specific. That is, the assets have little value outside  
2 the regulatory transaction. The regulatory contract that was suited for an industry with  
3 significant asset specificity is not suited for an industry in which asset specificity has  
4 declined considerably.

5  
6 This problem of incompatibility between the degree of asset specificity and the regulatory  
7 regime arises in the transition to competition: Incumbent utilities have not yet recovered the  
8 costs of their assets that are specific to a regulated market, and entrants meanwhile can  
9 invest in facilities that have considerably less asset specificity or can provide service with  
10 minimal investment. Of course, as noted previously, the Act also recognizes this fact  
11 through, for example, its definition of stranded costs in section 2803 as generation-related  
12 costs “which traditionally would be recoverable under a regulated environment but which  
13 may not be recoverable in a competitive electric generation market.” It would breach the  
14 regulatory contract for the regulator to make unilateral changes in regulation that might  
15 prevent a utility from recovering the economic costs of investments that it made to  
16 discharge its regulatory obligations to serve. Contractual protections of the interests of the  
17 utility and its investors exist so that the state and private companies can continue to make  
18 agreements requiring investments in highly specialized capital. The regulatory contract  
19 depends on protections to reduce and allocate the risk of cost recovery for specialized  
20 assets that cannot be salvaged if the contract is not performed.

21  
22 **Q. What is the significance of regulatory “hold-up” to the regulatory contract?**

23 **A.** As with private contracts, the regulatory contract is designed to address “hold-up”  
24 problems. By incurring substantial capital expenditures to perform its obligation to  
25 serve, the utility is vulnerable to confiscation. In the absence of contract enforcement,  
26 the utility is at the mercy of the regulatory authority: By lowering rates to levels that do

1 not allow a full recovery of costs, after the facilities have been created, a regulator  
2 could take advantage of the utility and its investors. The prices posted by a utility can  
3 be raised or lowered without incurring more than the costs of communicating the new  
4 tariffs to customers. The regulated rates are thus much more flexible than are the  
5 utility's capital facilities because the latter are irreversible, market-specific investments.  
6 *To the extent that they were tailored to meet regulatory obligations to serve, the*  
7 *utility's investments may not be fully recovered in a competitive market setting. Once*  
8 *again, to use the Act's formulation, investments which "traditionally would be*  
9 *recoverable under a regulated environment . . . may not be recoverable in a competitive*  
10 *electric generation market." That means that the regulatory contract is necessary as a*  
11 *means of protecting the regulated utility from regulatory "hold-up."*

12  
13 **Q. How does regulatory opportunism affect the utility's "core" customers?**

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

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

4  
5 **Q. What is the significance of credible commitments to the regulatory contract?**

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

15  
16 [R]ecovery should be allowed for legitimate stranded costs. The equity  
17 reason for doing so is clear, but there is also a strong efficiency reason  
18 for honoring regulators' promises. Credible government is key to a  
19 successful market economy, because it is so important for encouraging  
20 long-term investments. Although policy reforms inevitably impose  
21 losses on some holders of existing assets, good policy tries to mitigate  
22 such losses for investments made based on earlier rules . . . .

23  
24 1996 ECONOMIC REPORT OF THE PRESIDENT 817. The utility's investors would not be  
25 willing to commit vast amounts of capital to carry out an obligation to serve unless the  
26 regulator's offer of an opportunity to earn a fair rate of return were credible. Regulated

1 utilities relied upon those contractual assurances in planning and carrying out their  
2 investment and service plans. Conversely, the regulator would not be willing to provide  
3 a franchise protected by entry regulation and to authorize the utility's pricing and  
4 investment plans unless the utility's promises to provide services were credible. The  
5 legal and public policy context in which the regulatory process operates provides  
6 guarantees to the parties to the regulatory contract.

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

20  
21 **Q. What is the significance of relational contracting to the regulatory contract?**

22 **A.** A question sometimes asked in regulatory proceedings is, "Where, Professor X, is this  
23 regulatory contract to which your testimony refers?" The regulatory contract is  
24 recorded in a bundle of documents not necessarily limited to a single franchise  
25 agreement: *public utility statutes, utility commission precedents, adjudicatory decisions,*  
26 *rulemakings, hearings on the record, formal notices of proposed rulemaking, and public*

1 commentary. Such reasoning is not novel, for it is the same logic that the Supreme  
2 Court has applied in analyzing whether state legislation has given rise to a contractual  
3 obligation:

4  
5 In general, a statute is itself treated as a contract when the language  
6 and circumstances evince a legislative intent to create private rights of a  
7 contractual nature enforceable against the State. In addition, statutes  
8 governing the interpretation and enforcement of contracts may be  
9 regarded as forming part of the obligation of contracts made under  
10 their aegis.

11  
12 *United States Trust Co. v. New Jersey*, 431 U.S. 1, 17 n.14 (1977). Although the  
13 original franchise agreement between the public utility and a municipality is usually the  
14 critical first document in the bundle of agreements concerning the relationship between  
15 the state and the utility, no single document is likely to encapsulate the entire regulatory  
16 contract. The relational contract between the utility and the regulated firm is analogous  
17 to a corporation, which is an easily identified entity but consists of multiple contracts  
18 that define the firm.

19 Professor Victor Goldberg of Columbia Law School has observed that private  
20 contracts involve both an *ongoing relationship* that uses “rough formulae or mutual  
21 agreement to adjust the contract to current situations,” and *agency*, which occurs when  
22 a firm deals with many customers who “find it desirable to act collectively through an  
23 agent both to negotiate the terms and to administer the contract over time.” Victor P.  
24 Goldberg, *Regulation and Administered Contracts*, 7 BELL J. ECON. 426, 428, 429  
25 (1976). Goldberg asserts that “[r]egulation can be viewed as an implicit administered  
26 contract in which both elements are significant.” *Id.* at 427.

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

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

21  
22      **Q.    What economic inefficiencies can result from denying utilities the full recovery of  
23            their stranded costs?**

24      **A.    Denying utilities the reasonable opportunity to recover stranded costs can raise utilities'**  
25          **cost of capital and discourage future investment in the industry. That result reflects the**  
26          **fact that the allocation of risk between a utility's investors and customers differs from**

1 its allocation in unregulated industries. Unregulated markets impose on investors the  
2 full costs of investments that turn out badly but let them keep all the profits of ventures  
3 that turn out well. Under traditional utility regulation, however, investors have neither  
4 borne much of the former risk nor enjoyed much of the latter benefits. Instead,  
5 regulators only allowed utilities to earn a fair rate of return based on just and  
6 reasonable prices.

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

18 It is true that it will be too late for current investors in utilities to do anything in  
19 response to a prohibition of recoupment. But investors can learn the lesson and  
20 conclude that investment in electric utilities is to be avoided assiduously in the future.  
21 More important, other prospective investors, seeing the contract abrogated, are certain  
22 to conclude that it may well be abrogated again whenever it is convenient for the  
23 regulator, and they, too, may take their resources elsewhere in the economy. Investors  
24 would demand a significant risk premium to provide incumbent utilities with the capital  
25 that they will need in the future to maintain and improve the transmission and  
26 distribution facilities that will be required to serve both themselves and their new

1 competitors in electricity generation. The resulting shortage of capital for the electric  
2 power industry, and the consequent impediments to maintenance, modernization, and  
3 needed expansion, can hardly benefit the long-run interests of consumers or contribute  
4 to the efficiency and competitiveness of the economy.

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

#### 11 **D. The Principal Components of the Regulatory Contract**

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

13 **A.** The three components of the regulatory contract are entry controls, rate regulation, and  
14 utility service obligations. The state commission controls the entry of the utility's  
15 competitors and authorizes rates that give the utility's investors the opportunity to earn  
16 a "fair" rate of return on their investment. In return, the regulated utility must comply  
17 with regulatory accounting procedures for the disclosure of its costs, abide by price  
18 regulations, limit its business activities in other markets, invest in sufficient generation,  
19 transmission, and distribution services to all customers within its service territory who  
20 request service, operate efficiently as determined by the regulatory commission, make  
21 only investments that are "prudent," meet regulatory standards for quality of service,  
22 and comply with a host of other provisions. For example, as recently as February of  
23 1997, the Supreme Court described the origin of the regulatory contract in the gas  
24 industry in these terms: "It seemed virtually an economic necessity for States to provide  
25 a single, local franchise with a business opportunity free of competition from any  
26

1 source, within or without the State, so long as the creation of exclusive franchises  
2 under state law could be balanced by regulation and the imposition of obligations to the  
3 consuming public upon the franchised retailers.” *General Motors Corp. v. Tracy*, 117  
4 S. Ct. 811 (1997). The Court noted that there occurred “essentially the same evolution  
5 in the electric industry.” *Id.*

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

13  
14 [T]he generation, transmission, distribution, and retail sale of electricity  
15 is provided generally by public utilities under bundled rates regulated by  
16 the Commission. The procedures established under this chapter provide  
17 for a fair and orderly transition from the current regulated structure to a  
18 structure under which retail customers will have direct access to a  
19 competitive market for the generation and sale or purchase of  
20 electricity.

21  
22 *Id.* Finally, section 2802(15) of the Act confirms the existence of utility service  
23 obligations, and that, “consistent with [those] obligation[s], [Pennsylvania utilities]  
24 have undertaken long-term investments in generation, transmission and distribution  
25 facilities in order to meet the needs of their customers.” Those service obligations,  
26 which began during the period of municipal contracting with utilities and which were

1 greatly expanded by the Pennsylvania public utility code, were in some ways expanded  
2 even further by the Act.

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

11

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

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

23 The traditional justification for entry restrictions in the electric power industry  
24 has been to achieve the cost gains from *natural monopoly*. A technology exhibits the  
25 property of natural monopoly if one firm can produce the product or service at lower  
26 cost than can two or more firms. Competition brings cost efficiencies and incentives for

1 innovation that cannot be achieved through entry and rate regulation. Moreover, the  
2 high transaction costs associated with cost-of-service regulation lead many to question  
3 whether any potential cost gains can possibly justify continuing to regulate entry.

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

11  
12 **Q. Does the regulatory contract grant the incumbent utility a statutory monopoly?**

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

26 Suppose that a state not only forbade exclusive franchises, but also failed to

1 create—by statute, common law, or regulatory practice of long standing—any  
2 alternative cost recovery mechanism that credibly assured the utility that the regulator  
3 would provide the utility the opportunity to recover its irreversible, nonsalvageable  
4 investments. In that institutional setting, a private company would be reluctant to  
5 contract for the long-term supply of any amount of electricity that would necessitate  
6 any incremental investment in nonsalvageable assets; and even if the company *were*  
7 willing enter into such a contract, investors would be unwilling to supply the company  
8 with the requisite capital unless they were paid a risk premium substantial enough to  
9 compensate for the risk that the capital used to make those investments in  
10 nonsalvageable assets might never be recovered and a competitive return on that  
11 capital might never be received. That sort of risk premium is what investors routinely  
12 demand from irreversible investments in third-world countries that suffer from political  
13 instability and correspondingly unreliable judicial and regulatory institutions for the  
14 protection of private property. Most important, consumers suffer under such  
15 circumstances because it is they who ultimately pay the risk premium that is necessary  
16 to attract the investment required for the utility to render service, and it is they who will  
17 bear the disruption in service if regulatory instability induces the public utility to  
18 disinvest.

19 It should therefore be evident where the fallacy lies in the second argument—  
20 that is, the argument that the existence of a statute or state constitutional provision that  
21 forbids the state or any of its municipalities from granting an exclusive franchise  
22 disproves the existence of the regulatory contract in that state. It is a factual matter  
23 beyond any dispute that some states forbid the grant of an exclusive franchise. The  
24 existence of such a prohibition, however, is hardly evidence that the regulatory contract  
25 does not exist in that state. All that such a fact proves is that the state has chosen a  
26 different means by which to achieve the ends for which franchise exclusivity is the

1 chosen means in other states. The common objective in the two cases is to create the  
2 opportunity for recovery by the utility of the prudently incurred costs of irreversible,  
3 nonsalvageable investments that it made to discharge its obligation to serve customers  
4 within its service area. For example, a state, while not granting exclusivity to the  
5 incumbent utility, may nonetheless refrain from taking actions that would threaten the  
6 firm's recovery of nonsalvageable investments. That limitation on the discretion of the  
7 licensing authority may include the statutory directive to the public utilities commission  
8 not to grant an overlapping certificate of public necessity without good cause.

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

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

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

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

24

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

26 A. Yes. As a general rule in antitrust law and in markets generally, a firm may unilaterally

1 refuse to deal with any prospective customer. That rule does not apply to public  
2 utilities, however. Utilities carry an obligation to serve customers in their franchise  
3 region at posted prices. That obligation requires the utility to expand its generation,  
4 transmission, and distribution capacity to meet the growth and location of customer  
5 demand and to provide reliable service. Indeed, as noted earlier, the Act actually  
6 continues and expands the service obligations of incumbent utilities like PECO Energy.

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

16  
17 **Q. Why is it necessary to obligate a utility to extend its network?**

18 **A.** For a fixed, geographically averaged price, the utility would stop expanding its network  
19 when the private marginal cost of doing so began to exceed the private marginal  
20 benefit. Regulators would prefer to have the network expanded to the point where  
21 *social* marginal cost equals *social* marginal benefit. Alternatively, the utility would  
22 depart from pricing its services at a fixed price and, instead, charge higher prices to  
23 customers in high-cost areas. Thus, the need to impose on the utility an obligation to  
24 extend its network is the direct implication of policies of universal service and rate  
25 averaging. For example, in *New York ex rel. New York & Queens Gas Co. v. McCall*,  
26 245 U.S. 345, 351 (1917), the Supreme Court said:

1  
2 Corporations which devote their property to a public use may not pick  
3 and choose, serving only the portions of the territory covered by their  
4 franchises which it is presently profitable for them to serve and  
5 restricting the development of the remaining portions by leaving their  
6 inhabitants in discomfort without the service which they alone can  
7 render. To correct this disposition to serve where it is profitable and to  
8 neglect where it is not, is one of the important purposes for which these  
9 administrative commissions, with large powers, were called into  
10 existence . . . .

11  
12 If a public utility having a uniform rate structure and a franchise protected by entry  
13 regulation is meeting or exceeding its revenue requirement, then it cannot refuse a  
14 request to extend its network to serve a new customer below incremental cost.

15  
16 **Q. How does the regulatory contract regulate service quality?**

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

1 useful tests for cost recovery.

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

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

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

23 In the case of electric power, the utility must maintain sufficient generation,  
24 transmission, and distribution capacity to meet the pattern of demand with baseload,  
25 shoulder, and peaking capacity. Because the cost of storing power is prohibitive, and  
26 because regulators do not permit rationing of residential and commercial customers,

1 the utility must recover the costs of capacity through demand charges based on  
2 maximum use, and through energy charges. Moreover, the utility provides standby  
3 capacity because it must remain prepared to serve customers that self-generate or  
4 purchase power elsewhere, whenever they have additional needs for power.

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

16  
17 **Q. Does the utility's obligation continue after a customer has ceased to subscribe to**  
18 **service?**

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

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

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

8  
9 **Q. In what sense is "excess" capacity currently used and useful?**

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

25 Consumers of electric power currently benefit from all of those possible  
26 consequences. Although at first glance it may appear otherwise, a benefit such as the

1 avoidance of capacity shortages is not different in principle from direct financial  
2 benefits, such as lower operating costs. Each benefit has a savings in costs that  
3 corresponds to and appropriately measures its economic value, even if that value  
4 cannot be definitively quantified in monetary terms. For example, consumers clearly  
5 benefit if the utility has enough additional generation capacity to reduce the risk of  
6 outages and network failure. Provision against risk is a tangible product that is bought  
7 and sold in a market at observable prices, as the existence of the insurance industry  
8 attests.

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

15  
16 **Q. How does the regulatory contract constrain the utility's freedom to exit markets?**

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

25  
26 **II. DEREGULATORY TAKINGS**

1 Q. **What is a “deregulatory taking”?**

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

17

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

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

24

25 **A. Physical Invasion of Network Facilities**

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

1           **property?**

2       A.     A physical invasion of property compelled by the state gives rise to an absolute right of  
3           compensation. The leading decision on takings arising from physical invasion of  
4           property is the Supreme Court's 1982 decision in *Loretto v. Teleprompter Manhattan*  
5           *CATV Corp.*, 458 U.S. 419, 421 (1982), which defended that rule even in the case of  
6           "a minor but permanent physical occupation of an owner's property authorized by  
7           government." The Court announced that "when the character of the governmental  
8           action, is a permanent physical occupation of property, our cases uniformly have found  
9           a taking to the extent of the occupation, without regard to whether the action achieves  
10          an important public benefit or has only minimal economic impact on the owner." *Id.* at  
11          434-35 (quoting *Penn Central*, 438 U.S. at 124) (citation omitted).

12  
13       Q.     **How did *Loretto* arise?**

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

1 facts here.)

2

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

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

17

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

2 A. No. The Court said that “constitutional protection for the rights of private property  
3 cannot be made to depend on the size of the area permanently occupied.” *Id.* at 436  
4 n.12. The Court made light of the factual disagreement between the majority and the  
5 dissenters over the volume of the cable boxes attached to Ms. Loretto's building. “The  
6 displaced volume . . . . [is] not critical: whether the installation is a taking does not  
7 depend on whether the volume of space it occupies is bigger than a breadbox.” *Id.* at  
8 438.

9

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

12 A. Writing for the majority, Justice Marshall reasoned that a government policy permitting  
13 the permanent physical occupation of private property without compensation would be  
14 harmful to society as a matter of first principles, and that such considerations animated  
15 the precedents upon which the Court relied in *Loretto*. “Property rights in a physical  
16 thing,” he reasoned, are “the rights `to possess, use and dispose of it,” and the  
17 government's permanent physical occupation of private property “destroys each of  
18 these rights.” *Id.* at 435 (quoting *United States v. General Motors Corp.*, 323 U.S.  
19 373, 378 (1945)). Justice Marshall noted in particular that “the owner has no right to  
20 possess the occupied space himself, and also has no power to exclude the occupier  
21 from possession and use of the space. The power to exclude has traditionally been  
22 considered one of the most treasured strands in an owner's bundle of property rights.”  
23 *Id.* at 435–36 (citing *Kaiser Aetna*, 444 U.S. at 179–80; RESTATEMENT OF PROPERTY  
24 § 7 (1936)). A powerful economic rationale supports that conclusion, for the power to  
25 exclude is a prerequisite to voluntary exchange, allocative efficiency, and investment.

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

9  
10 Q. **Would mandatory retail wheeling, unaccompanied by the simultaneous lifting of**  
11 **incumbent burdens and the imposition of a mechanism to permit full recovery of**  
12 **stranded costs, constitute a taking under *Loretto*?**

13 A. Yes. Because of the technological and economic complexity of interconnection and  
14 unbundling in the electric power industry, it is easy to overlook the obvious:  
15 Mandatory interconnection and unbundling constitute a government-ordered, physical  
16 invasion of the property of the incumbent utility. Electric utilities have rights of way,  
17 poles, conduits, transmission lines, and the like. Indeed, to build that physical  
18 infrastructure, an electric utility originally had to acquire the consent of the land owner  
19 or, if it was exercising the right of eminent domain, pay just compensation for its  
20 taking. *See Loretto*, 458 U.S. at 429, 437. Mandatory interconnection or unbundling  
21 requires rivals of the regulated firm to have physical access to its property. The Oregon  
22 Supreme Court has recognized that fact and, relying upon *Loretto*, held unanimously in  
23 1995 that the state PUC's order that enhanced service providers be allowed to co-  
24 locate their equipment on the premises of incumbent local exchange carriers constituted  
25 a physical invasion that violated the Takings Clause. *GTE Northwest, Inc. v. Public*

1           *Util. Comm'n of Ore.*, 321 Ore. 458, 468–77, 900 P.2d 495, 501–06 (1995), *cert.*  
2           *denied*, 116 S. Ct. 1541 (1996). The court emphasized that “the facts that an industry  
3           is heavily regulated, and that a property owner acquired the property knowing that it is  
4           heavily regulated, do not diminish a physical invasion to something less than a taking.”  
5           321 Ore. at 474, 900 P.2d at 504.

6  
7           **Q.     Can a physical invasion of the incumbent utility's property occur when the**  
8           **physical occupation is not visible?**

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

19  
20           **Q.     How does retail wheeling physically occupy the incumbent utility's property?**

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

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

16  
17       **Q.    When is the compensation paid for a taking of private property “just”?**

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

1  
2 Q. **As an economic matter, what does that rule for just compensation imply for the**  
3 **compensation to which an electric utility would be entitled for the government-**  
4 **mandated physical invasion of its transmission and distribution network?**

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

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

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

24  
25 **B. Uncompensatory Rates for Public Utilities**

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

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

5  
6 Q. **Does the *Duquesne* decision answer the takings questions presented if retail  
7 wheeling were to produce uncompensated stranded costs for incumbent utilities?**

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

20  
21 Q. **How did the *Duquesne* case arise?**

22 A. In *Duquesne*, the Duquesne Light Co. began making investments in new nuclear power  
23 plants. (Several other utilities were involved in *Duquesne*, but for simplicity I refer only  
24 to Duquesne.) Those investments were reasonable (prudent) in light of the current  
25 costs of different production technologies and expected future demand at the time they

1           were made. Changes in the relative costs and risks of nuclear power (for example, the  
2           Three Mile Island nuclear mishap) resulted in a further (prudent) decision to abandon  
3           the nuclear power plants. Duquesne had spent roughly \$35 million in planning and  
4           preparation by that time. 488 U.S. at 302. Duquesne sought to add those sunk costs to  
5           its rate base and to recover them through amortization and the allowed rate of return.  
6           Unfortunately for Duquesne, however, Pennsylvania enacted legislation after the  
7           expenditure but before the inclusion of the nuclear costs in the rate base that foreclosed  
8           the Pennsylvania Public Utility Commission from granting Duquesne recovery of those  
9           costs through higher utility rates. *Id.* at 303–04. The Court examined whether the state  
10          legislation caused a taking of the property of Duquesne's shareholders without just  
11          compensation.

12                 Writing for the Court, Chief Justice Rehnquist noted that Duquesne had “a  
13          state statutory duty to serve the public” and that its “assets are employed in the public  
14          interest,” but that the company was “owned and operated by private investors.” *Id.* at  
15          307. Those characteristics set the regulated firm apart from others: “This partly public,  
16          partly private status of utility property creates its own set of questions under the  
17          Takings Clause of the Fifth Amendment.” *Id.* Whether the allowed rates of a public  
18          utility violate the Takings Clause depends on whether they are “confiscatory.” *Id.* at  
19          307–08. The answer to that question, however, does not depend on the use of any  
20          single methodology. The *Duquesne* Court reaffirmed the holding in *Hope* that it is the  
21          overall effect of rate regulation, not the details or methods, that matter: “[I]t is not  
22          theory but the impact of the rate order which counts. If the total effect of the rate order  
23          cannot be said to be unreasonable, judicial inquiry . . . is at an end. The fact that the  
24          method employed to reach that result may contain infirmities is not then important.”  
25          *Hope*, 320 U.S. at 602, *quoted in Duquesne*, 488 U.S. at 310. The question in  
26          *Duquesne* then was whether the rate of return that was achieved was constitutionally

1 sufficient. The Court considered the unrecovered sunk costs as part of the investment  
2 on which to measure the overall rate of return.

3  
4 **Q. Why does *Duquesne* fail to answer the takings questions presented if retail  
5 wheeling were to produce uncompensated stranded costs for incumbent utilities?**

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

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

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

24  
25 No argument has been made that these slightly reduced rates jeopardize

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

6  
7 488 U.S. at 312. Again, breach of the regulatory contract unquestionably *does*  
8 jeopardize the financial integrity of certain electric utilities.

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

13  
14 The risks a utility faces are in large part defined by the rate  
15 methodology because utilities are virtually always public monopolies  
16 dealing in an essential service, and so relatively immune to the usual  
17 market risks. Consequently, a State's decision to arbitrarily switch back  
18 and forth between methodologies in a way which required investors to  
19 bear the risk of bad investments at some times while denying them the  
20 benefit of good investments at others would raise serious constitutional  
21 questions. But the instant case does not present this question.

22  
23 *Id.* at 315. Justice Scalia, joined by Justices O'Connor and White, concurred but  
24 warned, more forcefully than did Chief Justice Rehnquist's opinion for the majority,  
25 that the holding in *Duquesne* would not answer the question of whether just  
26 compensation would be due in future takings cases where the nature and magnitude of

1 the utility's prudent investment differed substantially from Duquesne's:

2  
3 [W]hile “prudent investment” (by which I mean capital reasonably  
4 expended to meet the utility's legal obligation to assure adequate  
5 service) need not be taken into account as such in ratemaking formulas,  
6 it may need to be taken into account in assessing the constitutionality of  
7 the particular consequences produced by those formulas. We cannot  
8 determine whether the payments a utility has been allowed to collect  
9 constitute a fair return on investment, and thus whether the  
10 government's action is confiscatory, unless we agree upon what the  
11 relevant “investment” is. *For that purpose, all prudently incurred*  
12 *investment may well have to be counted.* As the Court's opinion  
13 describes, that question is not presented in the present suit, which  
14 challenges techniques rather than consequences.

15  
16 *Id.* at 317 (Scalia, J., concurring) (emphasis added). Breach of the regulatory contract  
17 *does* present the serious constitutional question that *Duquesne* did not, for it threatens  
18 to exploit the utility's irreversible investment to a far greater extent than does the  
19 opportunistic disallowance of costs through prudence reviews or other retrospective  
20 mechanisms.

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

26 In short, although *Duquesne* forced utility investors to bear the losses from

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

9  
10 Q. **How would you summarize your testimony?**

11 A. I have examined whether it would be “just and reasonable” under the Electricity  
12 Generation Customer Choice and Competition Act for the Commission to permit  
13 PECO Energy full recovery of its stranded costs pursuant to its restructuring. Both  
14 economic theory and the economic history of public utility regulation give content to  
15 the legal requirements of the “just and reasonable” standard of sections 2804(13),  
16 2804(14), and 2808 of the Act. That economic analysis supports my conclusion that it  
17 would be “just and reasonable” under the Act for the Commission to permit PECO  
18 Energy full recovery of its stranded costs. Historical evidence substantiates the  
19 existence of a “regulatory contract,” and compelling economic arguments confirm the  
20 need for such a contract between the electric utility and the state. A Pennsylvania utility  
21 expected, under traditional regulatory practice, to receive a reasonable opportunity to  
22 earn revenues sufficient to recover all of its prudently incurred investments and a  
23 competitive return on those investments. Pennsylvania would breach its regulatory  
24 contract with PECO Energy if the Commonwealth were to order retail wheeling  
25 without allowing PECO Energy to achieve full recovery of the stranded costs of its  
26 prudently incurred investments. Moreover, a failure by Pennsylvania to allow PECO

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

3

4 Q. Does this conclude your testimony?

5 A. Yes.

## APPENDIX: PROFESSIONAL QUALIFICATIONS

1  
2 Q. Please state your professional qualifications and educational background.

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

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

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

1 with Professor Baumol, is directly relevant to the issues in this proceeding.

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

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

24

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

1           **matters.**

2       A.     I have provided testimony in the following matters:

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

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

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

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

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

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

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

11 7. Direct Testimony of J. Gregory Sidak on behalf of GTE North  
12 Inc., Petition of Sprint, Public Utilities Commission of Pennsylvania (Nov. 7,  
13 1996).

14 8. Direct Testimony of J. Gregory Sidak on behalf of GTE  
15 Midwest Inc., Petition of MCI, Public Utilities Commission of Indiana (Nov. 1,  
16 1996).

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

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

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

1 Albany, Sept. 18, 1996).

2 12. Rebuttal Testimony of J. Gregory Sidak on behalf of Central  
3 Power and Light Company *in* Application of Central Power and Light  
4 Company for Authority to Change Rates, Competitive Issues Phase, Public  
5 Utility Commission of Texas, SOAH Dkt. No. 473-95-1563, PUCT Dkt No.  
6 14965 (filed Aug. 1, 1996).

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

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

16 15. Affidavit of Michael J. Doane, J. Gregory Sidak, and Daniel F.  
17 Spulber, appended to Reply Comments of GTE Service Corporation *in*  
18 Implementation of the Local Competition Provisions in the Telecommuni-  
19 cations Act of 1996, Federal Communications Commission, CC Dkt. No.  
20 96-98 (filed May 30, 1996).

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

1                   17.    *Technological, Environmental and Financial Issues Raised by*  
2                    *Increasingly Competitive Electricity Markets, Hearings before the*  
3                    *Subcommittee on Energy and Power of the House Committee on Commerce,*  
4                    104th Congress, 2d Session (Mar. 28, 1996).

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

8                   19.    Reply Comments of J. Gregory Sidak, Market Entry and  
9                   Regulation of Foreign-affiliated Entities, Notice of Proposed Rulemaking,  
10                  Federal Communications Commission, IB Dkt. No. 95-22 (filed May 12,  
11                  1995).

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

15                  21.    *Competition and Regulatory Policies for Interactive*  
16                  *Broadband Networks*, in Competition Policy, Regulation and the Information  
17                  Economy: Submission of the Director of Investigation and Research, Bureau of  
18                  Competition Policy, to the Canadian Radio-television and Telecommunications  
19                  Commission, Public Notice CRTC 1994-130, Order in Council P.C. 1994-  
20                  1689 (Ottawa, Jan. 16, 1995), co-authored with Robert W. Crandall.

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

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APPENDIX A - PROFESSIONAL QUALIFICATIONS OF JOSEPH F. BRENNAN

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1

**I. QUALIFICATIONS**

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

3 **A. My name is Joseph F. Brennan. I am Chairman of the Board of AUS Consultants.**

4 My business address is P.O. Box 1050, Moorestown, New Jersey 08057-1050.

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

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

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

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

16 The Utility Services Group specializes in every aspect of ratemaking,  
17 including rate of return, depreciation, cost of service, tariff design, valuation,

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1 demand-side management, lead/lag studies, and ratemaking accounting. Services  
2 have been performed for natural gas, electric, telephone, water, wastewater, cable  
3 television, maritime shipping, railroad, bus transportation, steam heating, and other  
4 enterprises whose price of service is established by a governmental or regulatory  
5 body.

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

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

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



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

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

6    A.   Yes.

7    Q.   Please explain.

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

17           In my opinion, only if market data are employed can the regulator ensure,  
18           over the long run, the utility's ability to meet its service obligations. Assurance of

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1       adequate service can only be achieved if earnings are sufficient to permit: (1) the  
2       attraction of an adequate amount of capital at a reasonable cost; (2) the  
3       maintenance of the integrity of presently invested capital; and (3) a return on  
4       common equity commensurate with returns on investments in other enterprises  
5       having corresponding risks. These standards for a fair rate of return have been well  
6       established by the U.S. Supreme Court in the Bluefield Water Works and  
7       Improvement Company v. Public Service Commission, 252 U.S. 679 (1922) and  
8       Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

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

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

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### III. SUMMARY

1

2 Q. **What is your recommendation?**

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

13 The estimate of the market-required cost rate for common equity capital of  
14 11.60% is PECO-specific and is the product of an independent study I performed.  
15 I also performed an independent study based upon information pertaining to  
16 barometer group companies of similar, but not identical, investment risk as one  
17 check of the appropriateness of the common equity cost rate included in my overall  
18 rate of return recommendation. The average estimated market-required cost rate  
19 for common equity appropriate for the barometer group companies of similar, but

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1 not identical, investment risk is 11.30%. I also observed other financial information  
2 and performed other calculations as a check on the reasonableness of my estimate  
3 of the common equity cost rate included in my overall rate of return  
4 recommendation as I will explain later in my testimony. A summary of my  
5 calculations as to the overall rate of return and the after-tax discount rate is shown  
6 on Schedule 1. A summary of the development of the cost rate for common equity  
7 capital is shown on Schedule 2.

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

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IV. RISK EVALUATION

1

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

4 A. Yes.

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

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

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

16 A. Yes, in the sense that the amount of business risk present in an enterprise  
17 influences the manner in which that enterprise should be financed over time. A

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1 higher degree of business risk generally requires the employment of less financial  
2 leverage, i.e., less debt and preferred stock and more common equity. For  
3 clarification, it should be noted that it is not possible, nor is it necessary, at all  
4 times for any entity to maintain whatever is considered the appropriate capital  
5 structure mix of debt and equity.

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

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

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

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

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

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

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

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

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1 barometer group should be used as a check.

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

4 A. I employed several criteria, which are: (1) companies with an S.I.C. Code of 4911  
5 (Electric Services) or 4931 (Electric and Other Services Combined); (2) companies  
6 with common stock which is actively traded; (3) companies which operate in the  
7 Northeastern, Great Lakes, North Central, South Central, or Southeastern region  
8 of the continental United States (in conformance with the most recent regional  
9 groupings made by the Federal Energy Regulatory Commission's Bureau of Power);  
10 (4) companies with 1995 permanent capital of at least \$2 billion; (5) companies  
11 with at least 70% of their 1995 operating revenues derived from electric operations;  
12 (6) companies with a Moody's Investors Service (Moody's) bond rating of A3,  
13 Baa1, or Baa2 or an S&P bond rating of A-, BBB+, or BBB; and (7) companies  
14 which have paid common dividends and have not cut their common dividends since  
15 1992.

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

19 I have analyzed the financial and operating characteristics of the nine



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

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

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

19 I do not mean to suggest by these comments that methods other than DCF,

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1 such as CAPM, are completely reliable or that other methods are not used by  
2 investors. Indeed, as I will discuss later, as with DCF, the CAPM is not completely  
3 reliable. It is for this reason that a variety of methods should be employed to  
4 *minimize estimating error.*

### 5 VI. DATA UNDERLYING COMMON EQUITY 6 COST RATE RECOMMENDATION

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

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

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

3 A. On Schedule 3, I have shown a comparison of interest rates for long-term debt  
4 rated Aaa, Aa, A, and Baa. This historical information begins in 1955, the last year  
5 in which there was no inflation, and for each year thereafter and for the years 1995  
6 and 1996. by month, as well as the average for those years, and for 1997 for the  
7 months of January, February and through March 13, 1997. The information  
8 compares yields for public utility debt similarly rated to industrial debt and the  
9 spread between the two. Please observe that at March 13, 1997, public utility bonds  
10 rated Baa by Moody's were priced to yield 8.30%, or 17 basis points higher than  
11 industrial companies whose long-term debt is similarly rated. On page 3 of  
12 Schedule 3, I have shown forecasts published by Value Line Investment Survey  
13 (Value Line), S&P, and Blue Chip Financial Forecasts for several items including  
14 A rated public utility bonds and Treasury bonds. Please note that the three  
15 forecasts with respect to Treasury bonds ranged from a low of 6.6% to a high of  
16 7.2% and the average of the three estimates is approximately 6.8%.

17 On Schedule 4, I have shown the rate of return on average book common  
18 equity for PECO and the average for the nine barometer group companies at a spot  
19 moment in time in 1997 and for each of the five-year periods ending 1995 and 1990,  
20 respectively. At the moment, PECO's rate of return on average book common

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1 equity is 11.0%, or slightly lower than the average for the barometer group.

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

7 On Schedule 5, page 2, I have shown the Dow Jones Industrial (DJI) and the  
8 Dow Jones Utility (DJU) averages and the average yield on A rated public utility  
9 bonds for official turning points in business cycles from January 1962 to March  
10 1997. Please note that the DJI index increased 136% by March 1997 from the  
11 trough of March 1991 or the end of the last recession. Please also note that the  
12 DJU average during that same period of time increased but 3.3%. These data  
13 suggest the investment risk gap between utilities and non-utility companies has  
14 narrowed or perhaps for some utilities closed in the 1990's.

15 On Schedule 6, I have shown earnings/price ratio information for PECO and  
16 the average barometer group company. The period of time again is the same with  
17 respect to the information shown on Schedules 4 and 5. Please observe that the  
18 current earnings/price ratio for PECO is 10.9% compared to but 8.1% for the  
19 average barometer group company. It should be noted that an earnings/price ratio  
20 is most often a partial indication of the indicated required market return rate to

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1 attract common equity. It is a partial indication because the price reflects expected  
2 future earnings, but the earnings used in the computation are historical.

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

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

20 On Schedules 8 and 9, I have shown for each of the five years ended 1995,

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

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

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

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1 31, 1995. Please note that both PECO and the average barometer group company  
2 derive more than 90% of their revenues from electric operations and their annual  
3 kilowatt hour sales are similar, and they serve similar numbers of customers.  
4 Please also note that in terms of generating mix, PECO's mix includes just under  
5 69% nuclear, whereas the average barometer group company's nuclear generation  
6 is just over 26%. Generation mix, of course, is but one element of risk assessed by  
7 investors when establishing the price of stock.

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

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

20 As can be seen by referring to the information on Schedule 11, S&P believes

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1 that PECO's business position is somewhat below average, whereas the average for  
2 the barometer group companies is average.

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

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

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

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1 VII. DEVELOPMENT OF COMMON EQUITY COST RATE

2 A. DCF Method

3 Q. Briefly describe the constant growth DCF model.

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

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

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

18 A. The behavior of investors and thus the market as a whole is at odds with the

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1 required assumptions of the DCF model.

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

5 A. Yes.

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

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

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

17 A. Share price change is also driven by factors not reflected in the DCF model. For

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1 example, investors may expect a change in price-earnings multiples. There is no  
2 place in the DCF model to reflect an investor-expected change in price-earnings  
3 multiples. Yet most financial publications, such as the Wall Street Journal, publish  
4 price-earnings multiples as well as dividend yields undoubtedly because investors  
5 take into account price-earnings multiples in their buy-sell decisions.

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

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

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

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1 due to whole or partial deregulation, etc.

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

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

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

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1 from the premise that sustainable growth ( $b \times r$ ) was the appropriate growth rate  
2 to employ for DCF calculation purposes?

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

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

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1 yields among shares is the superior measure of investors' expected growth.

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

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

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

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

19 A. Yes. However, in July 1991 the FERC voted 5-0 to discontinue the publication of

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1 the Quarterly Index Update generic rate of return on common equity for electric  
2 utilities. The Quarterly Index was intended to be advisory-only. I am not aware  
3 of any single Order issued by the FERC in which the common equity cost rate  
4 finding was solely based on the advisory-only, generically-determined, DCF-derived  
5 common equity cost rate. During the period of time the advisory-only, DCF-  
6 derived, generically-determined return on equity was still published, the FERC  
7 considered methodologies other than DCF to arrive at a common equity cost rate.

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

10 **A. No. As recognized by FERC Staff witness, Mr. David Lengenfelder, the DCF**  
11 **model is producing unreasonably low cost of equity estimates, as stated in his**  
12 **testimony in Consumers Power Company (Docket No.s ER92-331-000 and ER92-**  
13 **332-000). Mr. Lengenfelder indicated that "in recent years the resulting DCF-**  
14 **derived cost of equity estimates have exhibited wide variation and in some instances**  
15 **have failed fundamental tests of logic. The DCF-derived cost of equity has been**  
16 **below, equal to, or slightly above the company's cost of debt." (Page 15 of Mr.**  
17 **Lengenfelder's October 19, 1992 testimony). Likewise, in Boston Edison Company**  
18 **(Docket Nos. EL93-150-000 and EL93-10-000), the initial decision (page 42)**  
19 **indicates that FERC Staff witness, Mr. Nicholas P. Lewnes, found "that the constant**

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1 growth model has produced aberrant results ... produced wide variations in results  
2 and in some cases failed fundamental tests of financial logic."

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

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

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

16 **A.** No. Every method or model requires the exercise of subjective judgment and no  
17 method or model proceeds from assumptions which may be completely valid.  
18 Accordingly, I believe the use of a variety of methods is more appropriate than is

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1 sole or primary reliance upon DCF.

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

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

4 The Indiana Utility Regulatory Commission, in a decision dated February 2,

5 1994<sup>1</sup> recognized the infirmities of the DCF model when it stated:

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

18 The Iowa Utilities Board<sup>2</sup>, in its final decision and Order issued June 17, 1994, also

19 recognized the infirmities of the DCF model when it noted that:

20 While the Board has relied in the past on the DCF model, in Iowa  
21 Electric Light and Power Company, Docket No. RPU-89-9, "Final  
22 Decision and Order" (October 15, 199), the Board stated: "[T]he  
23 DCF model may understate the return on equity in some  
24 circumstances. This is particularly true when the market is relatively

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25 <sup>1</sup> Public Utilities Reports - 150 PUR4th, Re: Indiana-American Water Company,  
26 Inc., Cause No. 39595, p. 168.

27 <sup>2</sup> Public Utilities Reports - 152 PUR4th, Re: U.S. West Communications, Inc.,  
28 Docket No. RPU-93-9, p. 459.

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1 volatile and the company in question has a market-to-book ratio in  
2 excess of one.' Those conditions exist in this case and the Board will  
3 not rely on the DCF return. (Consumer Advocate Ex. 367, See Tr.  
4 2208, 2250, 2277, 2283-2284.) The DCF approach underestimates the  
5 cost of equity needed to assure capital attraction during this time of  
6 market uncertainty and volatility. The Board will, therefore, give  
7 preference to the risk premium approach.

8 In addition, the New York Public Service Commission (NYPSC), approximately  
9 every ten years, conducts a generic proceeding regarding, among other issues, the  
10 determination of the cost rate for common equity capital for ratemaking purposes.  
11 In the proceeding which took place in the 1980's, the NYPSC determined that the  
12 DCF methodology was the appropriate methodology to employ. In July 1994, the  
13 co-facilitators (Administrative Law Judge and Chief of the Utility Finance Section  
14 of the Department of Public Office of Accounting and Finance) of the New York  
15 Public Service Commission released a recommended decision resolving Case 91-M-  
16 0509, a proceeding to consider financial regulatory policies for New York state  
17 utilities. The co-facilitators recommended generic allowed returns based on a  
18 weighting of the DCF and CAPM methods. Both facilitators stated in their  
19 recommended decision, "a number of experts consulted during the collaborative  
20 process contended that the rate of return method upon which the PSC has placed  
21 primary reliance, the DCF, is even more volatile than other single methods, and  
22 that the DCF tends to produce higher returns when stock prices are below book  
23 value and lower returns when stock prices are above book value." (Electric Utility



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1 a dividend yield for as long as three or six months, together with dividends yields  
2 as short as one day, may tend to result in a yield that may be more representative  
3 of the future than any one particular period or moment in time. There is no reason  
4 to believe that the yield for a particular day or a three- or six-month period is  
5 necessarily indicative of the future. Accordingly, I assume the use of several  
6 periods of time, or the average of several periods of time, as long as such time  
7 period is not too stale, may be more indicative of the future than any one particular  
8 period or moment in time, and may minimize the impact of a stock price which is  
9 an aberration. Incidentally, had I adopted the average of the PECO dividend yield  
10 for the twelve months ended February 28, 1997 of 7.2% with the March 19, 1997  
11 8.8% spot or current yield, to obtain what may be the yield representative of the  
12 future, the end result is also an 8.0% PECO dividend yield for DCF purposes.  
13 However, it should be noted that the method of taking into account past lower  
14 dividend yields for DCF purposes could understate the DCF-derived common  
15 equity cost rate that is appropriate for the future, particularly in the PECO  
16 circumstance where one of the driving forces of stock price change is investor-  
17 anticipated reaction to significantly lower forecasted earnings growth. For example,  
18 as I will later explain, Value Line lowered its December 1996 PECO earnings  
19 growth rate of 5.5% to 2.5% in mid-March 1997. It should be noted that my use  
20 of a PECO dividend yield of 8.0% at a time when the current yield is 8.8%, based

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1 on a stock price of \$20.50 assumes an implied average future price of \$22-1/2 per  
2 share. It is quite possible that during the next several months, the average yield  
3 derived from giving equal weight to current, three- and six-month average dividend  
4 yields will be higher than 8.0%. If that occurs, the PECO DCF-derived cost rate  
5 will be higher than the one developed at this time.

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

8 **A.** Yes. For example, a similar computation for the average barometer group  
9 company indicates a dividend yield of 6.1% compared with the PECO dividend  
10 yield of 8.0% before any recognition of the next period dividend, as is required by  
11 the DCF model. Not surprisingly, the growth rate for the average barometer group  
12 company, as I will later explain, is 4.6% compared with a PECO growth rate of  
13 2.8%. Thus, the sum of the lower dividend yield and the higher growth rate for the  
14 average barometer group company is very similar to the higher dividend yield but  
15 lower growth rate of PECO, keeping in mind that the investment risk for these two  
16 companies is very similar, as I previously stated. Thus, if one reaches back too far  
17 in time to develop a dividend yield based on a price that was reflective of a  
18 different growth rate than the growth rate of the moment, the end result may be  
19 an understated DCF-derived cost rate for common equity capital.

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### 2. DCF Growth Rate

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

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

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

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

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1 typically much lower than the number of estimates included in the I/B/E/S  
2 consensus.

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

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

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

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

18 **A.** Yes. In an article in the October 11, 1993 issue of Forbes, David Dremman

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

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

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

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

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

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

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

### 12 3. DCF Conclusion

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

16 A. As can be seen by referring to Schedule 17, the sum of the adjusted dividend yield  
17 and growth inputs I employed for PECO produce a 10.9% estimated cost rate. For

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1 the barometer group, using the identical methodology, the indicated cost rate is  
2 10.8%. I am not surprised that PECO's cost rate is slightly higher than the  
3 barometer group, since the barometer group is, in my judgment, slightly less  
4 investment risky for reasons I previously cited.

### 5 **B. Capital Asset Pricing Model**

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

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

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

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1   A.   Yes. Under the theory of CAPM, beta is a measure of the risk of a security  
2        compared with the risk of the market as a whole. The beta for the market is always  
3        equal to 1.00, and therefore companies whose securities have betas greater than  
4        1.00 are considered riskier than the market, while companies with betas less than  
5        1.00 are considered less risky than the market. CAPM is premised on the concept  
6        that risk-averse investors demand higher returns for assuming additional risk and,  
7        accordingly, higher risk securities are priced to yield higher returns than lower risk  
8        securities. Under CAPM theory, there is an incremental reward for bearing  
9        additional risk (as measured by beta) above the base risk-free rate which is the  
10       return available from investing in U.S. Government Treasury Securities. The  
11       specific formula of CAPM is expressed as:

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

13        where:

14        K    =  required return

15        R<sub>f</sub> =  risk-free rate

16        B    =  beta

17        R<sub>m</sub> =  required return on the market

18  
19    **Q.   Should the CAPM model be employed exclusively to gain insight as to the market-**  
20    **required cost rate for common equity?**

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

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### 1. Risk-Free Rate of Return

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

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

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

13 A. There are advocates that would argue that the use of T-Bills is the appropriate  
14 riskless rate. There is substantial academic support for the use of a long-term  
15 relatively riskless rate such as a T-Bond yield as opposed to a much shorter term  
16 T-Bill yield in a CAPM computation as the risk-free (also referred to as riskless)  
17 rate. Here I have reference to a publication Stocks, Bonds, Bills and Inflation -  
18 1996 Yearbook, authored by Roger Ibbotson. Specifically, Ibbotson has observed

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1 in regard to the cost of capital in a regulatory proceeding:

2 Most utilities are regulated by local government bodies -- usually a  
3 commission appointed to ensure that the utility, because of its alleged  
4 monopolistic power, does not take advantage of its customers *and* that  
5 the investors in the utility receive a fair rate of return on their  
6 invested capital. One of the most important functions of the  
7 commission is to determine an appropriate (often called the 'allowed')  
8 rate of return. The procedures for setting rates of return for  
9 regulated utilities often specify or suggest that the required rate of  
10 return for a regulated firm is that which would allow the firm to  
11 attract and retain debt and equity capital over the long term. (pp.  
12 144-145)

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

### 20 2. Market Premium

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

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

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

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

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1            *Arithmetic Versus Geometric Differences*

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

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

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

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

14          A.    Yes.

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

17          A.    As I have already discussed, there is considerable doubt related to the reliability of  
18            the DCF model. Further, and more importantly, my intent was to develop an  
19            estimate of the common equity cost rate appropriate for rate of return purposes  
20            using different methodologies. Had I employed a DCF methodology to estimate

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1 the market premium for CAPM computation purposes, the end result would have  
2 been the sole use of a single method DCF, rather than two independent methods.

### 3 3. CAPM Conclusion

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

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

### 8 VIII. COMMON EQUITY COST RATE CONCLUSION

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

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

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

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

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

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

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

1  
2

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

5 A. Yes. There are two ways.

6 Q. Please explain.

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

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

14 A. Yes. In order to obtain a specific bond rating, one needs to have the opportunity  
15 to experience a specific level of before-income tax interest coverage. That is one  
16 of the criteria published by S&P. For electric companies whose long-term debt is  
17 rated A, the level of coverage necessary is 4.15 times. For BBB, the standard is  
18 3.15 times. The midpoint of A and BBB is 3.65 times.

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1           As can be seen by referring to Schedule 1, if PECO can achieve an 11.6%  
2           return on common equity, its implicit before-income tax interest coverage would be  
3           3.64 times, or almost identical to the derived 3.65 times midpoint published by S&P  
4           for an A and BBB bond rating. PECO's long-term debt is rated BBB+.

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

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

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

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

17          **A. Yes. For example, Peter A. Bradford and Richard K. Silkman co-testified before**  
18          **this Commission in conjunction with PECO's application for issuance of a Qualified**  
19          **Rate Order under Sections 2808 and 2812 of the Public Utility Code regarding the**

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1 recovery of half its stranded investment that such recovery was improper.

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

3 A. No, I do not.

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

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

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

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

17 *There are 29 states in which, at the moment, there is an informational fact-*  
18 *finding workshop or study underway where legislation is pending. And, lastly, there*

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1 are five states in which there is no substantive activity underway or a decision has  
2 been made that no action is necessary.

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

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

8 A. Historically, government created circumstances whereby competition was limited  
9 for, among others, electric utilities. This benefit bestowed by government was not  
10 a gift to utilities and their investors. Rather, government expected and required  
11 electric utilities and their investors to pay a price by accepting opportunity return  
12 rates below those available in industries not protected from competition.  
13 Moreover, the utility was obligated to provide safe, reliable service all of the time  
14 to all customers who sought service, including the well-to-do and the not so well-to-  
15 do and including customers residing in sparsely populated rural areas as well as  
16 urban areas. Electric utilities and their investors met their end of the bargain by  
17 producing safe, reliable service to all who sought service at prices set by regulators  
18 which resulted in returns on investment below non-price regulated industries, as I  
19 will explain. Thus, if an investment in property was deemed prudent at the time

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1 the decision to invest was made, the price of service established by regulators  
2 reflected the opportunity to recover the cost of and a fair return on the investment  
3 over the life of the asset, when the property financed by investors was placed in  
4 service.

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

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

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

18 **A. Yes.** This Commission, in 1990, permitted PECO to put into effect a price of

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

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

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

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

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

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

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

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

16           The second model did not take into account dividend reinvestment.

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

19           The study covered 97 major electric and telephone utilities and utility

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1 holding companies and the S&P 400 Industrials, as well as approximately 800  
2 industrials derived from the Value Line Industrial Company Group. The study  
3 displayed 18 three-year holding periods, 17 four-year holding periods, 16 five-year  
4 holding periods, and one 20-year holding period for a total of 171 distinct  
5 hypothetical holding periods.

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

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

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

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

7 the common stockholders of 72% of all major electric and  
8 telecommunication utility companies earned a higher internal rate of  
9 return on investment than did the average stockholder of the major  
10 non-utility U.S. industrial corporations over the 21-year period 1972-  
11 1992; 45% higher based on the second method; and 73% higher  
12 based upon a third method.

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

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

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

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

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1           **compensated for the risk of electric utility stranded investment?**

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

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

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

14   A.   No. I have updated the study with regard to the first method employed for the  
15       period 1972 through 1996. I have also performed calculations for the period 1992-  
16       1996 and 1992 through February 1997 to determine if the conclusion would be the  
17       same. The period of time since 1992 is likely the period when investors perceived  
18       the possibility of loss due to stranded investment occasioned by electric utility  
19       deregulation. The method I employed to perform the updated implied total return

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1 calculation was identical to the method employed by Mr. Foley in his original study.

2 A summary of the results of the update are shown on Schedule 19.

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

4 **A.** The NARUC study reported that the percent of all electric and telephone utilities  
5 whose implied total overall return was greater than the industrial companies was  
6 72% based on averaging 171 different holding periods. If a single holding period  
7 had been utilized by NARUC, this figure would have dropped to 43%.

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

12 **Q. How did PECO fare?**

13 **A.** Utilizing the NARUC report's 1972-1992 study period, PECO's investor return was  
14 8.31% or lower than the 9.79% average of all telephones and electrics, electrics  
15 only at 9.56%, telephones only at 12.41%, and 10.18% for industrials. For the  
16 updated 1972-1996 and 1992-1997 periods, again, PECO fared worse than all other  
17 groups.

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

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

8 **A. Alternative Method to Determine Whether**  
9 **Electric Utilities Earned More than Non-Utility**  
10 **Investors from Cash Paid by Consumers**

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

14 A. Yes.

15 Q. **Please explain.**

16 A. Electric utility regulatory-determined service rates charged customers include a  
17 provision for an opportunity return to be paid investors for the recovery of and a  
18 return on investor-provided facilities. Normally, a uniform computation of the rate

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1 of return earned on a similar measure of value, common equity measured at book  
2 cost, would indicate if electric utilities earned more than non-utility industrials.  
3 However, since utility accounting permits the capitalization of the cost of capital  
4 used to finance plant under construction (allowance for funds used during  
5 construction (AFUDC)) but typical non-utility accounting does not, a comparative  
6 computation must recognize such difference. Utility service rates do not reflect the  
7 cash necessary to pay for AFUDC. It is strictly a bookkeeping entry. The offset  
8 of such costs are capitalized as an asset and included in the plant account. When  
9 the plant under construction is placed in service and when the regulatory  
10 commission authorizes service rates charged consumers to reflect a return on and  
11 recovery of the plant, then and only then do customers pay cash in service rates for  
12 the use of such property over the very long life of the property.

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

18 Q. Have you performed such calculations?

19 A. Yes. I reviewed data for the same companies that were included in the NARUC

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1 study for the period 1972-1992 and an updated period 1992 - 1995. The update had  
2 to end in 1995 because 1996 earnings data for most of the companies included in  
3 the study are not yet available. The results of my study are shown on Schedule 20.

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

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

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

14 A. There is no basis for asserting that electric utility investors, most particularly PECO  
15 investors, were compensated for the risk of stranded investment during the period  
16 1972 - 1992. In addition, since 1992 the industrial index earned significantly more  
17 than all of the utilities studied.

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

1  
2

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

5 A. No.

6 Q. What is the basis of your opinion?

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

17 As can be seen by referring to Schedule 21, the period reported net income  
18 available to common equity was about \$7.6 billion, but when AFUDC is removed,

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1 the income is but \$4.3 billion, or a difference of \$3.3 million of AFUDC income,  
2 a bookkeeping entry and non-cash. The regulatory intended period return was  
3 about \$9.1 billion, or \$1.5 billion more than the \$7.6 billion achieved return. Thus,  
4 when the sum of the \$1.5 billion actual return compared with the intended return  
5 is added to the \$3.3 non-cash derived bookkeeping return not recovered from  
6 customers, the aggregate shortfall is about \$4.8 billion, all related to utility plant  
7 provided by investors. AFUDC is, in effect, a promise of recovery from customers  
8 over the life of the plant and if there is no recovery of stranded investment related  
9 to plant, not only did investors not recover from customers' AFUDC, but also did  
10 not earn whatever was intended by regulators.

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

18 Q. Does that conclude your testimony?

19 A. Yes.

Appendix A

to the

Direct Testimony

of

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

1 Education, Business and Regulatory  
2 Experience of Joseph F. Brennan

3 Education

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

8 Non-Utility Employment

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

14 Utility Employment

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

22 During my employment with affiliates of the holding company, I had responsibility

1 for forecasting the cash requirements and income expectations of many of its operating  
2 subsidiaries. I also negotiated lines of credit with banks for operating subsidiaries.

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

14 Consulting Work - Nature of Work

15 I am Chairman of the Board of AUS Consultants, Mt. Laurel, New Jersey. In late  
16 1967, I founded Associated Utility Services, Inc., the predecessor to AUS Consultants.  
17 AUS Consultants (AUS) is an independent firm comprised of several different groups  
18 employing more than 200 full- and part-time people (utility ratemaking, valuation, market  
19 research, industry analysis, and C. A. Turner publications). The Utility Services Group  
20 specializes in every aspect of ratemaking, ranging from rate of return, depreciation, cost  
21 of service, tariff design, lead/lag studies, and ratemaking accounting. Services have been  
22 performed for natural gas, electric, telephone, water, wastewater, cable television,

1 maritime shipping, products pipeline, railroad, bus transportation, steam heating, and  
2 other enterprises whose price of service is established by a governmental or regulatory  
3 body. The Valuation Services Group values companies and assets (tangible and  
4 intangible), including the value of intelligence transfer and property in ad valorem tax  
5 cases. Valuation services are usually rendered primarily in conjunction with mergers,  
6 acquisitions, and leveraged buy-outs, in the non-regulated environment. The Market  
7 Research Group performs consumer market research, customer satisfaction surveys (for  
8 AT&T), surveys related to demand-side management, political pollings (ABC/Washington  
9 News Post), custom research for financial institutions (Merrill Lynch) and many Fortune  
10 500 companies. The Industry Analysis Group provides a full range of demand-side  
11 management services for electric, gas and water utilities, energy market strategy, and  
12 economic analyses of the auto industry and agricultural industries, as well as studies  
13 regarding market share and market dominance in both a regulated and unregulated  
14 environment. C. A. Turner Utility Reports provides utility financial data and derived  
15 ratios monthly and annually to about 1,000 subscribers which include utilities, regulators,  
16 individuals, brokerage firms, lawyers, and libraries.

1 Expert Testimony Offered Before Regulatory Bodies

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

17 Employment by Regulatory Agencies or Municipalities and Other Engagements

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

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

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

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

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

22 I have also offered testimony before the Regulatory Control Authority of

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

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

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

1 Partial List of Clients Served

2 ELECTRIC

3	Appalachian Power Company	Michigan Power Company
4	Arkansas Power and Light Company	Monongahela Power Company
5	Atlantic City Electric Company	Nantahala Power & Light Company
6	Canal Electric Company	Ohio Edison Company
7	Carolina Power & Light Company	Ohio Power Company
8	Columbus Southern Power Company	Ohio Valley Electric Company
9	Conowingo Power Company	Orange and Rockland Utilities, Inc.
10	Consumers Power Company	PECO Energy Company
11	Delmarva Power & Light Company	Pennsylvania Electric Company
12	Duquesne Light Company	Pennsylvania Power & Light Company
13	Fitchburg Gas & Electric Light Co.	Pennsylvania Power Company
14	Hawaiian Electric Company	The Potomac Edison Company
15	Indiana Michigan Power Company	Potomac Electric Power Company
16	Iowa-Illinois Gas & Electric Company	Tampa Electric Company
17	Kentucky Power Company	The Washington Water Power Company
18	Lockhart Power Company	West Penn Power Company
19	Metropolitan Edison Company	Western Massachusetts Electric

20 NATURAL GAS DISTRIBUTION AND PIPELINE

21	Algonquin Gas Transmission Company	Lone Star Gas Company
22	American Natural Gas Company	Michigan Power Company (Gas Div.)
23	Bay State Gas Company	National Fuel Gas Distribution Corp.
24	Buckeye Pipe Line Company	New Jersey Natural Gas Company
25	Carolina Pipeline Corporation	North Penn Gas Company
26	Citizens Gas & Coke Utility	Northern Utilities, Inc.
27	Columbia Gas of Maryland	Oklahoma Natural Gas Company
28	Columbia Gas of Pennsylvania	Panhandle Eastern Pipeline Company
29	Columbia Gas of West Virginia	Pennsylvania Gas Association
30	Consolidated Gas Transmission Corp.	Pennsylvania Gas & Water Company
31	Delmarva Power & Light Company	Peoples Natural Gas Company
32	East Ohio Gas Company	Philadelphia Electric Co. (Gas Div.)
33	Elizabethtown Gas Company	T.W. Phillips Gas & Oil Company
34	Equitable Gas Company	Providence Gas Company
35	Great Lakes Gas Transmission Co.	Public Service Co. of N. Carolina, Inc.
36	Honolulu Gas Company	The Southern Connecticut Gas Company
37	Hope Gas, Inc.	Texas Eastern Transmission Corp.
38	Hope Natural Gas Company	Transwestern Pipeline Company
39	Indiana Gas Company	UGI Corporation
40	Kentucky-West Virginia Gas Company	Virginia Electric & Power Co. (Gas Div.)
41		West Ohio Gas Company

1

WATER & SEWER

- |    |                                   |                                      |
|----|-----------------------------------|--------------------------------------|
| 2  | American Water Works Company      | Middlesex Water Company              |
| 3  | (over 30 subsidiaries)            | Monmouth Consolidated Water Company  |
| 4  | Artesian Water Company            | New Haven Water Company              |
| 5  | Atlantic City Sewerage Company    | Newtown Artesian Water Company       |
| 6  | Barnstable Water Company          | Pennichuck Water Works               |
| 7  | Bridgeport Hydraulic Company      | Pennsylvania Gas & Water Company     |
| 8  | Citizens Utilities Company        | Philadelphia Suburban Water Company  |
| 9  | Commonwealth Water Company        | Roaring Creek Water Company          |
| 10 | Edgartown Water Company           | St. Louis County Water Company       |
| 11 | Elizabethtown Water Company       | Seymour Water Company                |
| 12 | Florida Water & Utilities Company | Spring Valley Water Company          |
| 13 | Hackensack Water Company          | Utilities and Industries Corporation |
| 14 | Indian Rock Water Company         | Washington Water Power Company       |
| 15 | Kaanapali Water & Sewer Co.       | Western Pennsylvania Water Company   |
| 16 | Long Island Water Corporation     | York Water Company                   |

17

TELEPHONE

- |    |                                      |  |
|----|--------------------------------------|--|
| 18 | Bell Atlantic Corporation            | Rochester Telephone Corporation        |
| 19 | Bell of Pennsylvania                 | Virgin Islands Telephone Company       |
| 20 | Diamond State Telephone Company      | And over 50 operating subsidiaries of: |
| 21 | Chesapeake & Potomac Telephone Co.   | ALLTEL Corporation                     |
| 22 | Commonwealth Telephone Company       | Central Telephone Company              |
| 23 | Eastern Illinois Telephone Corp.     | Continental Telecom, Inc.              |
| 24 | Illinois Consolidated Telephone Co.  | GTE Corporation                        |
| 25 | Norfolk & Carolina Telephone Company | United Telephone System, Inc.          |
| 26 | Puerto Rico Telephone Company        | Vista-United Telecommunications        |
| 27 | Quincy Telephone Company             |  |

28

CATV

- |    |  |                                       |
|----|--|---------------------------------------|
| 29 | American Television                    | COMCAST Cable Communications, Inc.    |
| 30 | Communication Corporation              | Kern County Cable Television          |
| 31 | Bakersfield Cable Television           | LVO Cable, Inc.                       |
| 32 | Cable Owners Association - California, | National Cable Television Association |
| 33 | Connecticut, New England,              | National Cable Television Owners      |
| 34 | Pennsylvania, Rocky Mountain,          | Association                           |
| 35 | Vermont                                | San Juan Cablevision                  |
| 36 | Cablecom-General, Inc.                 | Warner Cable Corporation              |
| 37 | Canadian Cable Television              |                                       |

1 REGULATORY AND GOVERNMENTAL

2 Cities of Rochester, New York and  
3 Baltimore, Maryland--Transit  
4 City of Anchorage, Alaska  
5 City of New Orleans, LA  
6 Arizona Corporation Commission  
7 Baltimore County, Maryland  
8 Bucks County, Pennsylvania  
9 City of Philadelphia Gas Works  
10 Collier County, Florida  
11 Commonwealth of Puerto Rico

Delaware Public Service Commission  
re: all regulated utilities  
The Delaware River Bridge Commission  
State of Hawaii Department of  
Planning and Economic Development  
Internal Revenue Service Commission  
Medford Township, NJ  
U.S. Department of Justice--  
Washington Metro (D.C. Transit)  
The U.S. Virgin Islands

12 Memberships, Publications and Appearances

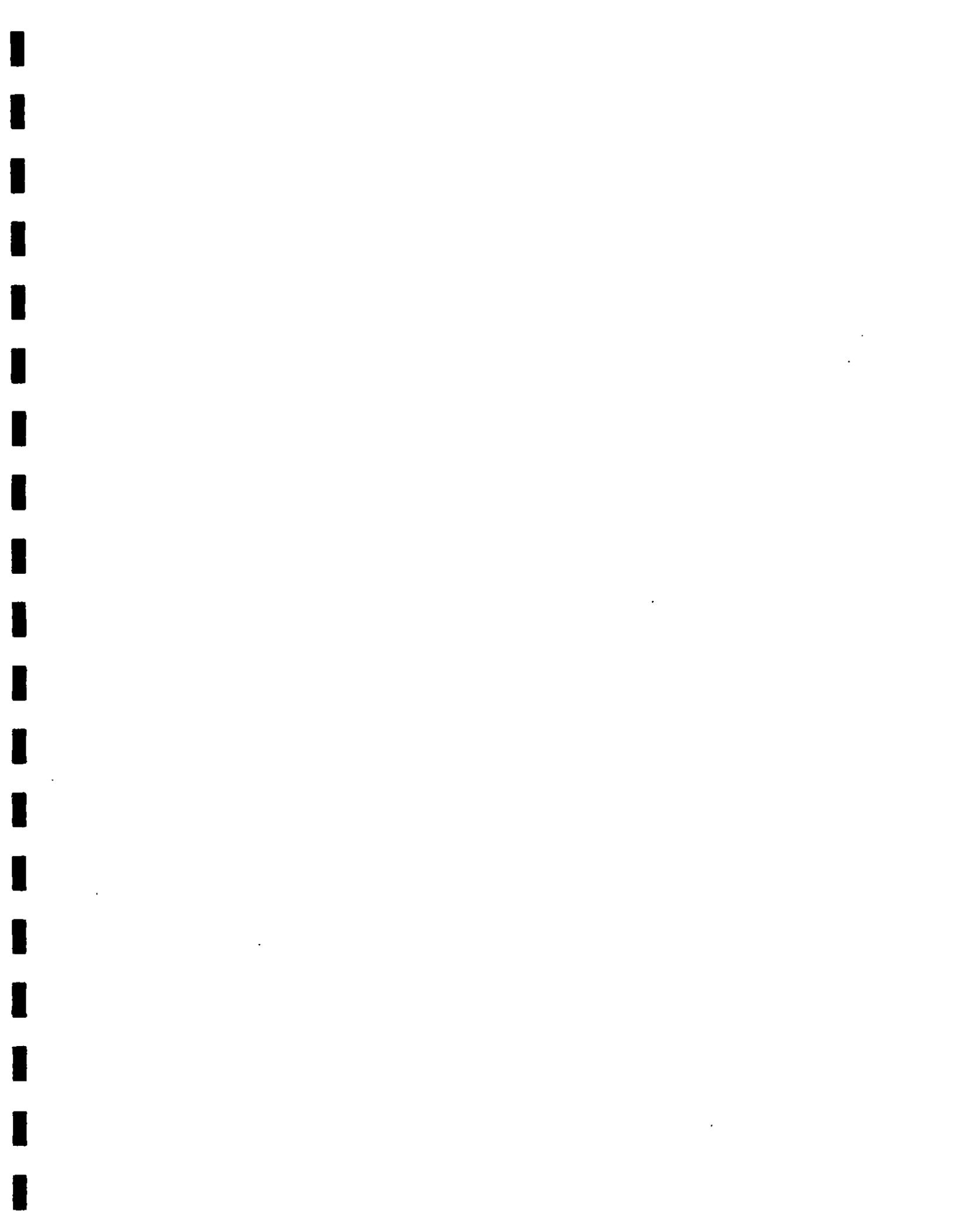
13 Memberships have included the Board of Directors of the Society of Utility and  
14 Regulatory Financial Analysts (SURFA) (formerly National Society of Rate of Return  
15 Analysts), the American Gas Association, the Pennsylvania Gas Association, the United  
16 States Telephone Association, the National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

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

26 In May 1970, 1979, and 1984, I appeared before the Iowa State University  
27 Conference on Public Utility Valuation and the Rate Making Process at Ames, Iowa. I

1 also addressed the Mid-America Regulatory Conference at Iowa State University at Des  
2 Moines in 1983. In addition, I appeared before two different Annual Conventions of the  
3 National Cable Television Association to discuss rate regulation of cable television. I  
4 have also appeared in a similar capacity before regional cable television conventions in  
5 Dallas, Texas; Augusta, Maine; New York, New York; Philadelphia, Pennsylvania;  
6 Lancaster, Pennsylvania; and San Diego, California. In 1973 and 1974, I was invited to  
7 appear at NARUC-sponsored seminars at the University of South Florida in St.  
8 Petersburg. My assigned subject was "Fair Rate of Return". During 1975, I appeared  
9 before the New Jersey Utilities Association and addressed the Annual Meeting of the New  
10 York Independent Telephone Association at Cornell University. I addressed an American  
11 Bar Association Seminar in Washington, D.C. or San Francisco, California, on the subject  
12 of cost of money in 1977, 1982, 1985, 1986 and 1987. I presented a paper to the NARUC  
13 Annual Convention in New Orleans on the subject of utility ratemaking. I also presented  
14 a paper in 1978 at The Greenbrier before the Great Lakes Section of NARUC. In May  
15 1979, I presented a paper in Columbus, Ohio, before the 2nd Annual Convention of the  
16 National Association of Regulatory Attorneys. I also made a presentation before a  
17 seminar conducted by the New Mexico State University in October 1979 and in May 1982.  
18 In April 1983, I delivered a speech concerning "Organizations in Transition:  
19 Telecommunications" at a forum sponsored by Arizona State University's College of  
20 Business Administration Alumni Association. I have presented prepared remarks before  
21 the American Gas Association's Finance and Rate Committees at Seminars in 1982, 1984,  
22 1987 and 1989. I made a presentation at a seminar regarding cost of capital co-sponsored

1 by Temple University in Atlantic City, NJ, in 1983. I presented remarks at the Edison  
2 Electric Institute's 1984 Financial Forum in Phoenix, Arizona. I delivered a speech in  
3 Washington, D.C., for the Utilities Law Institute in June, 1986, entitled "Differences in  
4 Regulation in a Lower Inflation, Lower Tax Rate, Low Growth Environment: Rate  
5 Decrease Proceedings, Vanishing Rate Base, Rate of Return Issues." In May 1989, I  
6 presented a speech entitled, "The Capital Structure: Regulatory vs. Real" at the annual  
7 SURFA convention in Washington, DC. In June 1989, I presented a speech on  
8 ratemaking matters before the Indiana CPA Society. In June 1990, I presented a speech  
9 entitled "A Financial Profile of New Jersey Investor-Owned Water Companies" at the  
10 meeting of the New Jersey Chapter of the National Association of Water Companies. In  
11 February 1992, I presented a speech before the Great Lakes Section of NARUC. In 1995,  
12 I presented a paper before the American Bar Association Regulatory Group in  
13 Washington, DC regarding implications of deregulation of energy and telecommunications  
14 utilities.



**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  
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to the Financial Supporting Exhibit  
of Joseph F. Brennan

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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

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

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

Years	Aaa Rated			Aa Rated			A Rated			Baa Rated		
	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	9.38	0.69	10.28	9.82	0.64	10.49	9.99	0.50	11.00	10.68	0.34
1989	9.32	9.19	0.13	9.58	9.38	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	9.88	9.77	0.09	10.08	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	8.88	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	8.08	7.88	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 %	(0.18) %
Jan.1995	8.50 %	8.38 %	0.12 %	8.68 %	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	8.08	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	6.88	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	8.00	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	8.08	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	7.68	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	7.84	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.

**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	0.38
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. Blue Chip Financial Forecasts(4)	2.7	1.9	N/A	N/A	6.8	5.3
	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

<u>Year</u>	<u>PECO Energy Company</u>	<u>Barometer Group of Nine Electric Companies (2)</u>
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 deferred 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

<u>Year</u>	<u>PECO Energy Company</u> <u>Average Book Value</u>	<u>Market/ Book Ratio</u>	<u>Barometer Group of Nine Electric Companies (2)</u>
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)		Dow Jones Utility (2)		Average Yield on 'A' Public Util. Bonds
	Avg. Index	% Chng.	Avg. Index	% Chng.	
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					Five-Year Average 1991-1995	February 1997 Percentage of Institutional Holdings (2)
	1995	1994	1993	1992	1991		
<u>PECO Energy Company</u>	<u>2.1</u>	<u>2.1</u>	<u>2.3</u>	<u>2.1</u>	<u>2.4</u>	<u>2.2</u>	<u>42.1</u> %
<u>Barometer Group of Nine Electric Companies</u>							
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
Energry 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.	<u>2.0</u>	<u>2.5</u>	<u>4.2</u>	<u>4.2</u>	<u>4.9</u>	<u>3.6</u>	<u>29.3</u>
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

<u>Year</u>	<u>PECO Energy Company</u> <u>Earnings</u> <u>Per Share</u>	<u>Earnings/</u> <u>Price Ratio</u>	<u>Barometer Group</u> <u>of Nine Electric</u> <u>Companies (2)</u>
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 deferred 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

<u>Year</u>	<u>PECO Energy Company</u>			<u>Barometer Group of Nine Electric Companies (3)</u>	
	<u>Dividends Per Share</u>	<u>Dividend Payout Ratio</u>	<u>Dividend Yield</u>	<u>Dividend Payout Ratio</u>	<u>Dividend Yield</u>
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 deferred 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	
(THOUSANDS OF DOLLARS)						
<u>AMOUNT OF CAPITAL EMPLOYED</u>						
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	
<u>INDICATED AVERAGE CAPITAL COST RATES (1)</u>						
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	
<u>FINANCIAL RATIOS-MARKET BASED</u>						<u>5 YEAR AVERAGE</u>
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
<u>CAPITAL STRUCTURE RATIOS</u>						
<u>BASED ON TOTAL PERMANENT CAPITAL:</u>						
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%
<u>BASED ON TOTAL CAPITAL:</u>						
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%
<u>COVERAGES-INCLUDING ALL AFUDC (2)</u>						
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
<u>COVERAGES-EXCLUDING ALL AFUDC (3)</u>						
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
<u>QUALITY OF EARNINGS</u>						
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.

	<u>Bond Ratings</u> <u>February 1997</u>	
	<u>Moody's</u>	<u>S&amp;P</u>
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

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

	<u>1995</u>	<u>1994</u>	<u>1993</u>	<u>1992</u>	<u>1991</u>	
<u>AMOUNT OF CAPITAL EMPLOYED</u>			(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	<u>\$6,903,800</u>	<u>\$6,862,550</u>	<u>\$6,591,120</u>	<u>\$6,011,040</u>	<u>\$5,978,490</u>	
<u>INDICATED AVERAGE CAPITAL COST RATES (2)</u>						
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	
<u>FINANCIAL RATIOS-MARKET BASED</u>						<u>5 YEAR AVERAGE</u>
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
<u>CAPITAL STRUCTURE RATIOS</u>						
<u>BASED ON TOTAL PERMANENT CAPITAL:</u>						
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	<u>43.3</u>	<u>41.5</u>	<u>40.9</u>	<u>40.5</u>	<u>39.2</u>	<u>41.1</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
<u>BASED ON TOTAL CAPITAL:</u>						
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	<u>42.1</u>	<u>40.1</u>	<u>39.8</u>	<u>39.5</u>	<u>38.3</u>	<u>40.0</u>
	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>	<u>100.0%</u>
<u>COVERAGES-INCLUDING ALL AFUDC (3)</u>						
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
<u>COVERAGES-EXCLUDING ALL AFUDC (4)</u>						
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
<u>QUALITY OF EARNINGS</u>						
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

Exhibit JFBr-1  
Schedule 9  
Page 2 of 3

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.

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

	Bond Ratings February 1997	
	<u>Moody's</u>	<u>S&amp;P</u>
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+

The names of the companies are:

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

	<u>PECO Energy Company</u>	<u>Barometer Group of Nine Electric Companies (1)</u>
(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) <u>Electric Generation Mix (1)</u>		
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	CI/Nergy Corp.	DQE, Inc.	DTE Energy Company	Entergy Corp. (1)	GPU, Inc.	Illnova 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%	38.7%	41.7%
(G) <u>Electric Generation Mix (1)</u>									
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 Storage	(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

	<u>PECO Energy Company</u>	<u>Barometer Group of Nine Electric Companies (1)</u>
<b>Customer Mix</b>		
(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)	<u>1.4</u>	<u>1.7</u>
Total	<u><u>100.0 %</u></u>	<u><u>100.0 %</u></u>
(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	<u>1.8</u>	<u>4.2</u>
Total	<u><u>100.0 %</u></u>	<u><u>100.0 %</u></u>
(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	<u>0.0</u>	<u>0.0</u>
Total	<u><u>100.0 %</u></u>	<u><u>100.0 %</u></u>

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.	Illnova Corp. (2)	PP&L Resources Inc. (3)
<b>Customer Mix</b>									
<b>(A) In Dollars of Revenue (\$):</b>									
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
<b>Total</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>
<b>(B) In Sales of MMKWH:</b>									
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
<b>Total</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>
<b>(C) In Number of Customers:</b>									
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
<b>Total</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>

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

	<u>Sales in</u> <u>Millions of Kilowatt Hours</u>			<u>Percent Increase</u>	
	<u>1986</u>	<u>1991</u>	<u>1995</u>	<u>1995</u> <u>over 1991</u>	<u>1995</u> <u>over 1986</u>
<u>PECO Energy Company</u>					
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
<u>Barometer Group of Nine</u> <u>Electric Companies (1)</u>					
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
<u>American Electric Power Co., Inc.</u>					
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
<u>Boston Edison Company</u>					
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)
<u>CINergy Corp. (1)</u>					
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
<u>DQE, Inc.</u>					
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
<u>DTE Energy Company</u>					
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)
<u>Entergy Corp.</u>					
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
<u>GPU, Inc.</u>					
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
<u>Illinova Corp.</u>					
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
<u>PP&amp;L Resources Inc.</u>					
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			February 1997 Standard & Poor's Bond Rating			Standard & Poor's Business Position (2)
	Bond Rating	Numerical Weighting (1)	Average Numerical Weighting	Bond Rating	Numerical Weighting (1)	Average Numerical Weighting	
PECO Energy Company	<u>Baa1</u>		<u>8.0</u>	<u>BBB+</u>		<u>8.0</u>	<u>Somewhat Below Average</u> <u>6.0</u>
<u>Barometer Group of Nine Electric Companies</u>							
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.	<u>NR</u>	<u>--</u>		<u>NR</u>	<u>--</u>		<u>Not Rated</u> <u>0.0</u>
Average	A3	7.4	7.4	A-	7.2	7.2	Somewhat Above Average      2.0
Boston Edison Company							
CINergy Corporation	Baa2		9.0	BBB		9.0	Average      4.0
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			February 1997 Standard & Poor's Bond Rating			Standard & Poor's Business Position (2)
	Bond Rating	Numerical Weighting (1)	Average Numerical Weighting	Bond Rating	Numerical Weighting (1)	Average Numerical Weighting	
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.	<u>Baa2</u>	<u>9.0</u>		<u>BBB</u>	<u>9.0</u>		<u>Low Average</u> <u>5.0</u>
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.	<u>A3</u>	<u>7.0</u>		<u>A-</u>	<u>7.0</u>		<u>Average</u> <u>4.0</u>
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.	<u>A3</u>		<u>7.0</u>	<u>A-</u>		<u>7.0</u>	<u>Average</u> <u>4.0</u>
Average for Barometer Group of Nine Electric Companies	<u>Baa1</u>		<u>8.0</u>	<u>BBB+</u>		<u>8.2</u>	<u>Average</u> <u>4.7</u>

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

<u>Moody's Bond Rating</u>	<u>Numerical Bond Weighting</u>	<u>Standard &amp; Poor's Bond Rating</u>
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-

<u>Numerical Weighting</u>	<u>Standard &amp; Poor's Business Position</u>
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

<u>Company</u>	<u>Jurisdiction</u>	<u>Rating</u>	<u>Numerical Weighting (1)</u>	<u>Average Numerical Weighting</u>
PECO Energy Company	PA	<u>Average 3</u>		<u>6.0</u>
<u>Barometer Group of Nine Electric Companies</u>				
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	<u>4.0</u>	
	Average			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	<u>4.0</u>	
	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	<u>4.0</u>	
	Average		6.3	6.3
GPU, Inc.	NJ	Average 1	4.0	
	PA	Average 3	<u>6.0</u>	
	Average		5.0	5.0
Illinova Corporation	IL	Average 3		6.0
PP&L Resources, Inc.	PA	Average 3		<u>6.0</u>
Average for Barometer Group of Nine Electric Companies		<u>Average 2 / Average 3</u>		<u>5.5</u>

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

<u>Rating</u>	<u>Numerical Weighting</u>
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

<u>Company</u>	<u>Jurisdiction</u>	<u>Date Authorized</u>	<u>Return on Equity Authorized</u>	<u>Average Return on Equity Authorized</u>
PECO Energy Company	PA (Elec)	4/19/90	12.75 %	
PECO Energy Company	PA (Gas)	1/15/88	<u>13.15</u>	
Average			<u>12.95 %</u>	<u>12.95 %</u>
<u>Barometer Group of Nine Electric Companies</u>				
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	<u>N/A</u>	(2)
Average			13.35 %	13.35 %
Boston Edison Company	MA	10/30/92		11.75 %
<u>CINergy Corporation</u>				
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	<u>11.50</u>	
Average			11.60 %	11.60 %
<u>DQE, Inc.</u>				
Duquesne Light Co.	PA	3/25/88		12.87 %
<u>DTE Energy Company</u>				
Detroit Edison Company	MI	1/21/94		11.00 %
<u>Entergy Corp.</u>				
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	<u>N/A</u>	(2)
Average			11.93 %	11.93 %
<u>GPU, Inc.</u>				
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	<u>N/A</u>	(2)
Average			11.73 %	11.73 %
<u>Illinova Corporation</u>				
Illinois Power Co.	IL (Elec)	2/11/92	12.40 %	
Illinois Power Co.	IL (Gas)	4/6/94	<u>11.24</u>	
Average			11.82 %	11.82 %
<u>PP&amp;L Resources, Inc.</u>				
Pennsylvania Power & Light Co.	PA	9/27/95		<u>11.50 %</u>
Average for Barometer Group of Nine Electric Companies				<u>11.95 %</u>

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

<u>Company</u>	February 1997 Standard & Poor's <u>Common Stock Ranking</u>		Value Line Safety <u>Ranking (3)</u>
	<u>Common Stock Ranking (1)</u>	<u>Numerical Weighting (2)</u>	
PECO Energy Company	<u>B</u>	<u>5.0</u>	<u>2.0</u>
<u>Barometer Group of Nine Electric Companies</u>			
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.	<u>A-</u>	<u>3.0</u>	<u>2.0</u>
Average for Barometer Group of Nine Electric Companies	<u>B+</u>	<u>4.0</u>	<u>2.8</u>

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:

<u>Numerical Stock Weighting</u>	<u>Standard &amp; Poor's Stock Ranking</u>
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			Average Dividend Yield (4)
	Spot (03-19-97) (1)	Average of Last 3 Months (2)	Average of Last 6 Months (3)	
PECO Energy Company	<u>8.8</u> %	<u>7.7</u> %	<u>7.4</u> %	<u>8.0</u> %
<u>Barometer Group of Nine Electric Companies</u>				
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.	<u>8.0</u>	<u>7.3</u>	<u>7.3</u>	<u>7.5</u>
Average	<u>6.3</u> %	<u>6.0</u> %	<u>6.0</u> %	<u>6.1</u> %

- 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)
<u>PECO Energy Company</u>	<u>\$20,500</u>	<u>\$23,583</u>	<u>\$24,208</u>	<u>\$22,764</u>
<u>Barometer Group of Nine Electric Companies</u>				
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	<u>\$29,319</u>	<u>\$30,347</u>	<u>\$29,933</u>	<u>\$29,867</u>

- 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)
<u>PECO Energy Company</u>	<u>\$1.800</u>	<u>\$1.800</u>	<u>\$1.790</u>	<u>\$1.797</u>
<u>Barometer Group of Nine Electric Companies</u>				
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.	<u>1.670</u>	<u>1.670</u>	<u>1.670</u>	<u>1.670</u>
Average	<u>\$1.794</u>	<u>\$1.790</u>	<u>\$1.783</u>	<u>\$1.789</u>

- 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		
<u>PECO Energy Company</u>	(4.5) %	(0.5) %	2.0 %	2.5 %	2.9 %	3.1 % [18]		2.8 %	2.8 %
<u>Barometer Group of Nine Electric Companies</u>									
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			Annual Common Equity Growth Rate (4)	ROE Adjustment Factor (5)	2000 - 2002					
	Common Equity (%) (1)	Total Capital (\$ mill) (1)	Common Equity (\$ mill) (1)	Common Equity (%) (1)	Total Capital (\$ mill) (1)	Common Equity (\$ mill) (1)			Return on Common Equity (1)	Return on Average Common Equity (6)	EPS (1)	DPS (1)	Retention Ratio (7)	Projected Internal Growth (8)
<b>PECO Energy Company</b>	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 %	2.8 %
<b>Barometer Group of Nine Electric Companies</b>														
American Electric Power Co., Inc.	43.70 % (9)	\$9,923.50 (9)	\$4,338.57	48.50 %	\$11,465.00	\$5,560.53	4.23 %	1.02	13.00 %	13.26 %	\$3.80	\$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
Illnova 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
<b>Average</b>														<b>4.2 %</b>

- 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  $\left(\frac{\text{column 6}}{\text{column 3}}\right)^{1/6} - 1$  or  $\left(\frac{\text{column 6}}{\text{column 3}}\right)^{1/6} - 1$ .  
(5)  $2 * \left(\frac{1 + \text{column 7}}{2 + \text{column 7}}\right)$ .  
(6) Column 8 \* column 9.  
(7)  $1 - (\text{column 12} / \text{column 11})$ .  
(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  $\left(\frac{\text{column 8}}{\text{column 3}}\right)^{1/5} - 1$ .

Source of Information: Value Line Investment Survey, January 10, and March 14, 1997

PECO Energy Company  
Discounted Cash Flow Model  
Summary of Conclusion

	<u>PECO Energy Company</u>	<u>Barometer Group of Nine Electric Companies</u>
1. Dividend Yield (1)	8.0 %	6.1 %
2. Dividend Growth Component (2)	<u>0.1</u>	<u>0.1</u>
3. Yield	8.1	6.2
4. Growth Rate (3)	<u>2.8</u>	<u>4.6</u>
5. Indicated Return Rate	<u>10.9 %</u>	<u>10.8 %</u>

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,  $8.0\% \times (1/2 \times 2.8\%) = 0.11\%$ , rounded down to 0.1% for PECO Energy Company and  $6.1\% \times (1/2 \times 4.6\%) = 0.14\%$ , 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)

	<u>Value Line Adjusted Beta</u>	<u>Company-Specific Risk Premium Based on Market Premium of 6.4% (2)</u>	<u>CAPM Result Including Risk-Free Rate of 6.8% (3)</u>
<u>PECO Energy Company</u>	<u>0.85</u>	<u>5.4 %</u>	<u>12.2 %</u>
<u>Barometer Group of Nine Electric Companies</u>			
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.	<u>0.75</u>	<u>4.8</u>	<u>11.6</u>
Average	<u>0.79</u>	<u>5.0 %</u>	<u>11.8 %</u>

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

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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  
 $\beta$  = 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)**

	<u>1972-1992</u>		<u>1972-1995</u>		<u>1992-1995</u>	
	<u>RETURN ON</u>		<u>RETURN ON</u>		<u>RETURN ON</u>	
	<u>AVERAGE</u>		<u>AVERAGE</u>		<u>AVERAGE</u>	
	<u>COMMON EQUITY</u>		<u>COMMON EQUITY</u>		<u>COMMON EQUITY</u>	
	<u>AS</u>	<u>ADJUSTED</u>	<u>AS</u>	<u>ADJUSTED</u>	<u>AS</u>	<u>ADJUSTED</u>
	<u>REPORTED (1)</u>	<u>TO EXCLUDE</u>	<u>REPORTED (1)</u>	<u>TO EXCLUDE</u>	<u>REPORTED (1)</u>	<u>TO EXCLUDE</u>
		<u>ALL AFUDC (2)</u>		<u>ALL AFUDC (2)</u>		<u>ALL AFUDC (2)</u>
<b>AVERAGE OF ALL UTILITIES (3)</b>	12.44 %	9.03 %	12.30 %	9.25 %	11.31 %	10.76 %
<b>AVERAGE OF ALL ELECTRIC UTILITIES</b>	12.35 %	8.74 %	12.20 %	8.97 %	11.12 %	10.55 %
<b>AVERAGE OF ALL TELEPHONE UTILITIES</b>	13.86 %	12.96 %	13.86 %	13.05 %	14.04 %	13.83 %
<b>PECO Energy Co.</b>	11.11 %	4.25 %	11.20 %	5.12 %	11.51 %	10.95 %
<b>EARNINGS/BOOK RATIO FOR MAJOR NON-REGULATED U.S. INDUSTRIAL COMPANIES (4)</b>	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**

Year	1		2	3	4	5	6	7
	Income Available as Reported (1) (\$ mill)	Excluding All AFUDC (2) (\$ mill)	Authorized Return Rate 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	3,486.513	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