Statement No. 21

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION

VS.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R 850152

DIRECT TESTIMONY

OF

ALFRED WROBLEWSKI

DEPRECIATION: ANNUAL ACCRUAL, ACCRUED RESERVE AND NET SALVAGE

SEPTEMBER 1985

Direct Testimony of Alfred Wroblewski

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

A. My name is Alfred Wroblewski, and my business address is 2301 Market Street, Philadelphia, Pennsylvania.

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

A. I am Staff Engineer in the Rate Division of the Philadelphia Electric Company.

Q. What is your educational background?

A. I graduated from the University of Pennsylvania in 1949 with a B.S. in Electrical Engineering. I also attended the Wharton Business School of the University of Pennsylvania and completed a number of graduate courses at Temple University and the University of Pennsylvania.

Q. Please outline your experience with the Philadelphia Electric Company.

A. I started with the Company as a Junior Engineer in 1949. I spent approximately two years in a training program in the operating department, two years in field engineering, three years in system planning, sixteen years in the Financial Division including seven years in supervision. I am presently a Staff Engineer in the Rate Division.

Q. Would you explain briefly your responsibilities in these assignments.

A. As a field engineer, I was responsible for the testing and approval of new electrical facilities prior to their acceptance for service. As a system planning engineer, I

made engineering planning and economic studies in connection with expansion of distribution facilities. In the Financial Division my major responsibility was plant mortality studies. In addition to that I participated in a broad range of financing activities involving issuance of new securities, statistical analyses of business trends, cash flow, economics, and depreciation, the latter in a supervisory capacity. Currently, as a Staff Engineer in the Rate Division, I am responsible for plant mortality and depreciation studies, developing depreciation rates used for both calculated and book depreciation, preparing exhibits relating to rate proceedings, testifying as the Company's witness on depreciation in rate proceedings before the Pa. PUC and FERC, and generally carrying out assignments from the Manager of the Rate Division.

Q. What are your professional affiliations?

A. I have been a member of the Edison Electric Institute Depreciation Committee for 13 years, serving as secretary and chairman. I participated in the development of numerous technical papers sponsored by the Committee and presented several papers and participated as a panelist at the National Conference of Electric and Utility Accountants in 1975. I have also been a member of the American Institute of Electrical Engineers and the Operation Research Society of America. Currently I am a member of the Ad-Hoc Depreciation Committee of the Pennsylvania Electric Association. I am registered as a

Professional Engineer in the Commonwealth of Pennsylvania.

Q. Would you outline your specific experience relating to matters covered by your testimony in this proceeding.

A. Yes. I have conducted plant mortality studies and reviews for the Company and its subsidiaries for more than twenty-five years. Since 1973, I have been primarily responsible for electric, gas, and steam heat system plant mortality studies, capital recovery studies, accrued depreciation calculations, and recommending plant life estimates for management approval. I have testified on depreciation issues in a number of major rate investigations before the Pennsylvania Public Utility Commission, including the Electric Cases at RID 129 in 1974, RID 295 in 1975, RID 438 in 1978, R-80061225, R-811626, R-822291 and R-842590, and Gas Rate Cases at RID 227 in 1975, R-811719 and R-832410. I also submitted testimony on depreciation issues before the Federal Energy Regulatory Commission in 1978, 1981, 1982 and 1983. I have also prepared depreciation studies and submitted testimony in the Company's steam heat rate cases.

In addition, I was principally responsible for the preparation of the Book Depreciation Study filed with the Commission in June, 1983.

Q. What areas will your testimony cover in the present proceeding?

A. My testimony will explain and support the development of the annual and accrued depreciation which is used in

developing operating income and the Company's claimed measure of value. I will also support the Company's five-year average experienced net salvage claim.

Q. Can you describe briefly how the annual and accrued depreciation were developed for purposes of this filing?

A. In accordance with the Commission's order at R-842590, the Company has adopted book depreciation with appropriate adjustments for ratemaking use. The annual book depreciation is calculated using the straight-line remaining life method based on life estimates developed in the Company's 1985 Plant Life Study, which is submitted as Exhibit AW-1 in this proceeding. As in prior filings, the life span technique is used for production plant (except Muddy Run) and the average-life technique is used for the other electric and common plant. These calculations are shown in detail by account in Exhibits AW-2 (Plant and Depreciation claimed in the Historic Test Year), and AW-3 (Plant and Depreciation claimed in the Future Test Year), for the test years ended June 30, 1985 and June 30, 1986, respectively.

Q. Would you describe the nature and purpose of the 1985 Plant Life Study, Exhibit AW-1.

A. This study is the foundation of the annual depreciation calculations included in the Company's rate filing. It uses plant retirement data, engineering and operating experience and current and future system plans, to develop plant life estimates by primary accounts.

Remaining life depreciation rates based on these life estimates are applied to surviving plant balances net of the accrued depreciation reserve to develop annual depreciation using the life-span technique for most production plant and group average-life depreciation for transmission, distribution and common plant.

Consistent with current regulatory practice these basic depreciation rates exclude salvage and removal costs, which are determined separately on the basis of the experienced five-year average.

Q. Are the life analysis techniques used in the 1985 Study consistent with practices and procedures accepted by the Pennsylvania Commission for ratemaking purposes?

A. Yes, life analysis techniques used in the 1985 Study are the same as those used in the Company's filing at R-842590. These techniques were reviewed and accepted by the Commission in that proceeding and are based on actuarial analysis of the Company's plant mortality experience and engineering plans for future production plant retirements.

Production plant, excluding Muddy Run, is analyzed using the life-span technique. Interim survivor curves for production plant accounts are developed using 1960-83 interim retirement experience primarily for steam production plant. These curves, along with production unit terminal dates estimated by the engineering department, are used to define the life span for each

production unit.

Transmission, distribution, general and common plant depreciation is based on the group remaining life technique. The average life and dispersion for each account is determined by actuarial analysis of 1965-83 retirement experience. Judgment along with available retirement experience is used to develop life estimates for accounts for which actuarial experience alone is inadequate.

The life estimates for the Muddy Run accounts are based on the available retirement experience as well as the life estimates used for the Conowingo Hydro facilities with the approval of FERC which licenses both facilities.

The results of the 1985 Study are summarized on pages 12 to 15 of Exhibit AW-1. Retirement dates used for production plant as determined by the Engineering Department are found on pages 16 to 18. Charts showing the original mortality data and the selected life Iowa survivor curve for each account analyzed are in Appendix A. Appendix B contains the actuarial data and calculations for each account analyzed.

Q. Is there a summary of the annual and accrued depreciation claimed by the Company in this proceeding?

A. A summary of the depreciation reserves and accruals for electric and allocated common plant appears on pages C-2 through C-6 with a summary of the related production plant life span data on page C-7 of Exhibits TPH-1 and TPH-2.

Pages C-2 and C-3 summarize the electric and allocated common plant in service and the book reserve and related ratemaking adjustments. The book reserve and adjustment figures are developed in Exhibit AW-2 and AW-3 for the historic and future test years respectively. Pages C-5 and C-6 summarize the remaining life annual depreciation for Electric and Common plant which is developed in Exhibits AW-2 and AW-3.

Q. Please explain how you developed the annual and accrued depreciation for each of the test years as shown on pages C-2 through C-6 in Exhibits TPH-1 and TPH-2, respectively.

A. The annual depreciation is developed by the calculations detailed in Exhibits AW-2 and AW-3 as previously noted. In each of these exhibits, the life estimates developed in the 1985 Life Study (Exhibit AW-1) and the net plant balances as of the end of each test year are used as the basis of the calculations which are summarized in the "C" sections of Exhibits TPH-1 and TPH-2.

Q. Please explain the nature of the calculations contained in Exhibits AW-2 and AW-3.

A. The calculation of depreciation for ratemaking purposes for a test year is based on the plant in service, the depreciation reserve and remaining life at year-end conditions. Exhibits AW-2 and AW-3 develop in detail the annual and accrued depreciation claimed for ratemaking purposes as of June 30, 1985 and June 30, 1986, respectively. These calculations use a uniform page

format and the following explanations generally apply to both exhibits. The explanation will focus on Exhibit AW-3 since it is the basis of the Company's claim in this proceeding.

Exhibit AW-3 consists of four sections. Section A develops the electric remaining life annual depreciation expense of $241,962,000 as of June 30, 1986 which is summarized on page A-12 and carried over to Exhibit TPH-2. Section C starts with the book depreciation reserve broken down by ratemaking segments as of the end of 1984 and updates it to the end of 1985. Section B updates the reserve from the end of 1985 to June 30, 1986 for use in Section A. Section D provides a sample calculation of remaining life depreciation accrual rates as used in the schedules in this exhibit.

Q. Do these calculations conform to the depreciation methods and procedures used in the Company's filing at R-842590.

A. Yes, these calculations do conform to the basic remaining life practices accepted by the Commission for ratemaking purposes in the proceeding at R-842590.

Q. Would you please explain in detail the development of the depreciation reserve used to develop the future test year net plant for rate base and depreciation purposes.

A. Yes, the electric book depreciation reserve of $1,633,742,000, (Exhibit TPH-2, pages C-2 and C-5) as of June 30, 1986, used for future test year rate base and depreciation accrual purposes is the recorded book reserve

of $1,495,215,893 as of the end of 1984, brought forward to June 30, 1986 on the basis of the estimated depreciation reserve debits and credits. The reserve update is made in Schedule IV of Section B and Section C of Exhibit AW-3. The depreciation accruals used to update the reserve are based on the 1984 Study life estimates used and approved in the proceeding at R-842590. These accruals are developed in Schedule II of Section B and Section C.

The book reserves for transportation and common plant (reference page C-3, TPH-2) totaling $51,600,000 are developed at the end of Schedule IV of Sections B and C, of Exhibit 3, along with the book reserve adjustments related to additional AFUDC and excess salvage appearing on page C-2 of Exhibit TPH-2. Common and transportation plant reserve allocated to electric is summarized on page C-2 of Exhibit TPH-2.

Q. Would you explain the book reserve adjustments on page C-2 of Exhibit TPH-2?

A. The book reserve adjustment related to the additional AFUDC allowed for ratemaking purposes on certain production plant common facilities is added to the recorded book reserve. This is necessary since the additional AFUDC and related depreciation is recognized for ratemaking purposes only.

The ($13,822,000) adjustment identified as excess salvage removes from the recorded book reserve certain

salvage payments which were not paid by ratepayers and therefore are not properly included in the depreciation reserve for ratemaking purposes.

Both of the preceding adjustments are consistent with the Commission's Order at R-842590.

Q. What is the purpose of the tables on pages C-2a through C-2g and C-5a through C-5f of Exhibit TPH-2?

A. These table summarize the results of depreciation calculations included in Exhibit AW-3 for easy reference.

Q. Would you explain the derivation of the 39-year life span used to develop the Company's claimed depreciation for Limerick No. 1.

A. Yes. Limerick No. 1 is licensed by the Nuclear Regulatory Commission to operate for a period of 40 years starting with the low-power license issued in 1984. The 40-year license period was reduced one year to allow for the estimated period of precommercial testing to arrive at the 39 year life-span estimate for depreciation purposes.

Q. How were the interim retirement curves estimated for the Limerick plant?

A. The interim retirement experience projected for Limerick is based on the Company's interim retirement experience of its fossil and other nuclear units. This experience is analyzed in the 1985 Plant Life Study and the results are summarized on page 12 in terms of the Iowa Curves listed for nuclear plant accounts.

Q. Would you explain the effect of the 15 year life extension

planned for Eddystone No. 1 and No. 2 and Cromby No. 1 coal units on the Company's depreciation claim?.

A. Since the 1984 Life Study, the Company has decided to extend the life of its coal-fired generating units, Eddystone No. 1 and No. 2 and Cromby No. 1, from 35 to 50 years as noted on page 18 of Exhibit AW-1. Accordingly, the Cromby Unit No. 1 terminal year has been changed from 1989 to 2004 and the Eddystone No. 1 and No. 2 terminal year has been changed from 1995 to 2010 as indicated on page 1 of Section A, Exhibit AW-3. These life extensions substantially decrease the Company's claimed annual depreciation expense.

Q. What is the status of the depreciation of Richmond No. 9 and Southwark Station in this filing?

A. Both Richmond No. 9 and Southwark Station, scheduled for retirement in 1985, are treated as fully depreciated for purposes of this filing. Accordingly, there is no claim for rate base or depreciation expense with respect to these facilities in this rate filing.

Q. Referring to page D-6 of Exhibit TPH-2, would you please explain the purpose of this schedule.

A. Yes. This page incorporates the adjustments necessary to change from depreciation expense as determined for accounting purposes to depreciation on a proforma, ratemaking basis.

The development of this adjustment starts with the total depreciation accrual for ratemaking purposes of

$243,486,000 taken from page C-5 of TPH-2. As shown on page C-5, the total depreciation for plant in service as of June 30, 1986 is $241,962,000, based on the remaining life method and the new 1985 Study life estimates. This is adjusted by $1,051,000 for the depreciation accrual on plant cost resulting from additional AFUDC taken for ratemaking purposes on production plant common facilities. The $473,000 expense adjustment on page C-5 is to amortize the excess salvage included in the book reserve as recognized by the Commission in its order at R-842590, over the remaining life of the related accounts.

The ($647,000) antitrust price adjustment is a continuing amortization of the antitrust settlement which has been claimed and approved in prior proceedings.

The experienced net salvage expense adjustment of $4,199,000 is consistent with the Commission findings in the prior case at R-842590 and is not adjusted to remove third party payments. The Company reserves the right to claim the third party adjustment in this case, should the appeal pending in Commonwealth Court pertaining to this matter be resolved in the Company's favor.

Q. Please explain why annual depreciation for ratemaking purposes on page D-6 of Exhibit TPH-2 is $251,986,000 which is some $92 million higher than the book depreciation of $160,239,000 for the test year ending June 30, 1986.

A. The test year book depreciation excludes approximately

$103 million of Limerick No. 1 annual depreciation which is included in the Company's ratemaking claim. This is offset by a substantial reduction in claimed depreciation due to the planned life extensions for Cromby No. 1 and Eddystone No. 1 and No. 2, the effects of which are not included in the 1985 budgeted book depreciation. These two changes primarily result in the $92 million increase in depreciation claimed for ratemaking purposes over the budgeted book depreciation.

Q. Does this complete your testimony?

A. Yes it does.

ORIGINAL

PECO STATEMENT NO. 22

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION
VS
PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

DIRECT TESTIMONY
OF
JOHN J. CARROLL

EXPLANATION OF COAL & OIL INVENTORY AND PRODUCTION PLANT EXPENSES; DEVELOPMENT OF LIMERICK FUEL SAVINGS

SEPTEMBER 1985

DOCKETED
SEP 27 1985

DIRECT TESTIMONY OF JOHN J. CARROLL

Q. Please state your name and business address.

A. John J. Carroll, 2301 Market Street, Philadelphia, PA.

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

A. I am employed by the Philadelphia Electric Company as Staff Engineer in the Services Division of the Electric Production Department.

Q. What is your educational background?

A. I graduated from Villanova University in 1952 with a degree of Bachelor of Mechanical Engineering.

Q. Please describe your work experience with Philadelphia Electric Company.

A. I joined Philadelphia Electric Company in 1952 as a junior engineer in the Station Operating Department, the predecessor of the Electric Production Department. In 1960, I was transferred to the Economy Division of the Station Operating Department and held supervisory positions in that division from 1965 to 1974. In

1974, I was appointed Engineer-In-Charge of the Cost Section, Services Division of the Electric Production Department and held that position until I assumed my current position in January, 1984. A description of my principal activities in each of these positions is set forth in Appendix A, as is a list of my professional affiliations and my prior participation in proceedings before the Pennsylvania Public Utility Commission.

Q. What is the purpose of your testimony?

A. My testimony will explain the adjustments to Revenue, Expenses, Income and Measure of Value as presented in the Exhibit TPH-2 that are a function of the Electric Production Department. The specific adjustments which I have prepared are:

- Page C-10; the fuel inventory levels and prices included in the Materials and Supplies adjustment.

- Pages D-10, D-10a, D-10b, D-10c and D-10d; the normalization of operating and maintenance expenses associated with the nuclear and fossil production plants.

- o Page D-11; the adjustment to the test year O&M expenses resulting from retirement of Richmond No. 9, Southwark No. 1 & No. 2 and Diesel and the selected Combustion Turbines.

- o Page D-16; the level of anticipated gross output from the Nuclear Generating Units.

- o Page D-18; the full year non-outage Operating and Maintenance expenses required by Limerick Station.

- o Page D-21; the Energy Cost Savings anticipated from the operation of Limerick No. 1 after the unit is placed in commercial operation.

In addition, I will explain the analyses which I have performed to assure that the future test year power production expenses shown on Schedules B-10 and B-11 of Exhibit TPH-2, after the specific adjustments, which I have made and excluding fuel expenses, are normal expenses appropriate as the basis for rate level establishment.

Q. In the materials and supplies claim of the Company covered in TPH-2 Page C-10, would you

please explain the basis for the inventory levels requested by the Company.

A. The Fuel Committee of Philadelphia Electric has established a policy for determining the amounts of inventory required and therefore fuel purchases necessary. This policy is on file with the Commission. For coal inventory in the Philadelphia Area, the supply must be sufficient to meet two times the predicted monthly burn (60 days supply) including a normal build-up in the winter to 70 days due to frozen coal and transportation problems; for No. 6 oil the supply must be sufficient for the monthly burn (30 days); and for No. 2 oil, the supply must be sufficient to provide approximately 72 hours of burn for each of our combustion turbine units in order to maintain area protection and system reliability in event of a major fuel supply interruption. These levels are required at the start of each month. The desired inventory levels are achieved by scheduling deliveries in conjunction with burns, during each month, to achieve the desired level at the start of the following month.

At the jointly owned minemouth plants the coal inventory level represents a 45 day burn at an 80% in-service capacity factor for both plants. The inventory level at these plants is only 45 days because of the direct tie with the coal mines which virtually eliminates the potential for transportation delays and interruptions.

Q. Please explain the basis for a 60 day supply for coal and a 30 day supply for oil.

A. The 60 day inventory level for Philadelphia area coal is required to assure maintenance of necessary service reliability based upon a consideration of the probable duration of loss of coal deliveries for various reasons. Reasons considered include rail and miners strikes, rail equipment problems, winter weather, Miners' Holiday, and inability to meet quality requirements of contracts. The interruption periods resulting from these potential disruptions vary from 120 days for a miners' strike to 2-3 days for track damage or holidays.

A similar analysis to that performed relative to coal inventories supports the claimed oil inventory levels. The reasons oil deliveries

could be disrupted include international problems affecting imports, barge strikes, refinery or terminal strikes, embargoes, river navigation problems due to ice, fog, accidents or barge availability, trucking problems due to ice, or strike, and production problems at refineries and terminals. The severity of these problems, exclusive of international problems, were estimated to be between 30 days for barge strikes and as little as one day for trucking problems.

Q. Based on the Company fuel inventory policy, how were the levels of inventory developed?

A. The Company used the ProdCost Model to predict the fuel burn at our various generating stations for the Future test year and one subsequent year, with a simulation of Limerick No. 1 unit in commercial operation for the entire period. Using the output from this prediction, the fuel requirements for Philadelphia Area Coal and No. 6 oil, both 0.5% and 1.0% sulphur, were determined for each month. These monthly requirements were then used as an input to the policy requirements to arrive at a starting inventory for each month. The values shown on TPH-2, C-10 are the average

of the monthly values developed for the years stated.

Q. What are the inventory levels requested in these proceedings?

A. The inventory levels for both coal and oil assume that Limerick No. 1 is commercially available and that Richmond No. 9, Southwark No. 1 & 2 and the selected internal combustion units are retired for the total time period. For Philadelphia coal, the inventory projection is 204,000 tons which is a decrease of 96,000 tons from the inventory level as was approved by the Commission in R-842590. This decrease reflects the lower coal burn that will be required with Limerick No. 1 available.

The minemouth coal inventory remains at 240,000 tons which represents 45 days burn at an 80% in-service capacity factor for both plants and is the same level as was approved by the Commission in R-842590.

The Philadelphia No. 6 oil 1.0% sulfur inventory level is 100,000 bbls which is an increase of 5,000 bbls from the inventory level approved by the Commission in R-842590 and represents 90,000

bbls of usable No. 6 oil 1.0% sulfur. This increase is due to a higher estimate of Cromby No. 2 Unit's generation for this period than was used to arrive at the 95,000 bbls approved in R-842590.

The Philadelphia No. 6 oil 0.5% sulfur inventory level is 350,000 bbls which is a decrease of 40,000 bbls from the inventory level as was approved by the Commission in R-842590 and represents 261,000 bbls of usable No. 6 oil 0.5% sulfur. This decrease reflects a reduction due to the retirement of Southwark 1 & 2 and the dead storage associated with that station.

The No. 2 oil inventory level is 263,000 bbls which is a decrease of 37,000 bbls from the inventory level approved by the Commission in R-842590. This decrease is due to the retirement of the selected internal combustion units.

Q. How were the prices shown in TPH-2 Page C-10 obtained?

A. The Fuel Procurement Department was requested to supply their prediction of the fuel prices that will be in existence in the future for the Philadelphia Area fossil stations. During the

process of preparing the prediction, discussions with the Fuel Procurement Department were held to review and understand the basis for and various factors which were used to prepare their estimate. As a result of this review process, I have accepted their predictions for use in these proceedings. With respect to the expected prices for coal at the minemouth plants, the Keystone-Conemaugh Project Office was requested to provide the forecasted prices expected at the end of the test year, considering their contracts with the mine operators and any changes in operation anticipated during the test year. The prices shown on Page C-10 are the result of this process.

Q. What is the effect on fuel inventory level due to Limerick No. 1 being placed in commercial operation?

A. The availability of Limerick No. 1, in the two years used to develop the inventory claim, substantially reduces the fossil fuel generation requirements due to the additional low cost nuclear generation produced by Limerick. Specifically, shown on the following table the inventory level changes due to Limerick No. 1

are: Philadelphia Area coal decreases by 96,000 tons, the No. 6 oil inventory for both 1.0% and 0.5% sulfur oil decreases by 137,000 bbls, and the No. 2 oil inventory decreases by 37,000 bbls.

Electric Fuel Inventory

	W/O Limerick	Claim	Decrease
Coal	Tons	Tons	Tons
Phila. Area	300,000	204,000	96,000
Keystone	121,000	121,000	-
Conemaugh	119,000	119,000	-
Oil	Bbls	Bbls	Bbls
No. 6-1.0%S	117,000	100,000	17,000
No. 6-0.5%S	470,000	350,000	120,000
No. 2	300,000	263,000	37,000

Q. Would you explain the basis for your adjustment to the nuclear and fossil plant production operation and maintenance expenses shown on TPH-2, Page D-10.

A. Page D-10 of TPH-2 summarizes the adjustments for nuclear plant expenses shown on Page D-10a, the fossil plant expenses shown on Page D-10b, the maintenance expense revisions as shown on Page D-10c and the amortization of a regulatory mandated non-recurring cost at Salem Station on D-10d. The adjustment listed in D-10c for the

maintenance schedule changes was the first adjustment developed as it affects the adjusted values used in establishing the normalized outage expenses for both nuclear and fossil units, where appropriate, as shown on D-10a and D-10b.

Q. Mr. Carroll, please explain the adjustment on TPH-2 Page D-10c.

A. Since the budgeting process is undertaken early in the summer prior to the start of the Budget Year, it is necessary to make certain assumptions regarding the timing of outages. These timing assumptions are made not only for the start and stop dates of the outages, but also with respect to when the expenses will be booked for the work completed.

Since the schedule for outages is dynamic and is changed based on the latest information, the outage schedules reflected in the final Budget may not reflect the latest available schedule when a rate case is filed. Thus, in order to determine the proper adjustment of anticipated expenses to normalized expenses shown for the nuclear and fossil plants on D-10a and D-10b respectively, it is first necessary to review the

latest projections for the outages and adjust the anticipated expenses for these outages included in the operating expenses listed in TPH-2 Page B-10 and B-11. That is the purpose of Page D-10c.

Q. Would you please explain the items listed on Page D-10c.

A. As explained above, the rescheduling of outages is a dynamic process and the first four items are adjustments to reflect this process. The Eddystone No. 2 outage, originally scheduled for the second half of 1985, was rescheduled into the first half of 1985. The Delaware No. 8 outage scheduled for the first half of 1986 has been rescheduled into the second half of that year. The adjustments for the outages at Peach Bottom Station are to move the 1986 outage on No. 2 unit beyond the test year and move the No. 3 unit outage into the second half of 1985.

The fifth item refers to the Swede Street Dam. These expenses were included in the 1985 Budget because the Company was not able to obtain the necessary permit from the Pennsylvania Department of Environmental Resources in time to perform the repairs in 1984. However, the recovery of these

expenses were part of the normalized adjustment to our maintenance expenses in R-842590 and referenced in the later discussion of Schedule D-10b. Therefore, this adjustment removes these expenses from the amount requested in this proceeding.

At Eddystone Station, failures were discovered in the Transition Tubes in No. 1 boiler. Inspection of these tubes showed that the material used was approaching the end of life and that a replacement program was needed to maintain boiler reliability. These tubes are in the low temperature convection section of the boiler which had not previously displayed significant problems, and therefore had not been included in the recently completed Restoration Program. An estimate of $3,578,000 was included in the 1985 budget to perform this replacement. Subsequent investigation showed that the replacement program could be completed for $3,400,000 and the impact on the outage lengths would be minimized if the replacement was scheduled for 50% completion in each of the next two outages. The adjustment shown here reduces the requested O&M expenses included in the budget by $1,878,000 and permits

the company to recover the level of expenses that will be incurred each year for the next two years to maintain the reliability of one of its Philadelphia Area coal units.

The last adjustment of $1,600,000 reduction for dredging expenses is made to correct the timing of dredging expenses in 1986 included in the Future test year expenses shown in TPH-2, Page B-10, as well as a reduction in 1985 projected expenses because of the cancellation of anticipated dredging projects at Cromby and Schuylkill Station.

Q. Would you explain the adjustment of $20,651,000 for normalized outage expenses as shown on TPH-2 Page D-10a.

A. The $20,651,000 is the difference between a normalized level of end of cycle outage expense for the Company's five nuclear plants and the actual expenses included in the test year for end of cycle outages. End of cycle outages occur once every 18 months on each unit or 2/3 of an outage per unit per year on a normalized basis. Thus, a normalized outage level for the Company's five nuclear units will be 3 1/3 outages per year

(2/3 x 5). The expense to perform these outages is $37,505,000. However, total outage expenses included in the budget were only $16,854,000, which reflects a complete end of cycle outage for both Peach Bottom 3 and Salem 1 during the test year. No outage expense for Limerick 1 was included in the Budget. Therefore, this additional $20,651,000 is required to provide for a normalized level of nuclear end of cycle outage expenses.

Q. What is the basis of the normalized outage expenses for Peach Bottom, Salem and Limerick?

A. The development of the normalized outage expenses (2/3 of an outage per year) is shown on Schedule 1 of this testimony. Basically, the value represents the Commission approved outage expenses for Peach Bottom and Salem (R-842590) and the projected expenses for a Limerick outage, corrected to reflect inflation to the Future Test Year time period. The normalized outage expenses used for Limerick No. 1 unit were developed by examining the most recent and projected future expenses for the Peach Bottom units and using this levelized value for the Limerick unit outage cost. This approach was taken to develop the

projected Limerick No. 1 outage costs, since both plants will have similar operating characteristics, both are Boiling Water Reactors and will undergo a refueling outage every 18 months. Also, refueling outages at Limerick will be governed by the same regional cost effects and will be under the same maintenance supervision and manpower cost impacts as is presently experienced at Peach Bottom.

Q. Why does the value for 2/3 of a Limerick end of cycle outage appear to be significantly higher than that of Peach Bottom?

A. Since Peach Bottom units are jointly owned, the value of 2/3 of an end of cycle outage represent only 42.49% of the total cost of an outage, whereas the value of an end of cycle outage for Limerick represents the full cost of an end of cycle outage.

Q. Would you please explain the $4,028,000 adjustment shown on TPH-2, Page D-10b for Normalized Fossil Outages.

A. The development of the normalized fossil outage expense of $22,728,000 as shown on Schedule D-10b

is shown on Schedule 2 of this testimony.

The starting amount for this development is the amount included in the Company's presentation in R-842590 ($21,611,000). Line two of Schedule 2 shows a correction to adjust to the Commission ordered inflation rate of 4.2%. This results in an Approved Value of $21,244,000 from R-842590. Then the following adjustments were made to reflect changes since the Commission issued that order: The first adjustment shows the removal of the normalized outage expenses for Southwark #1 & 2 units. (In the value presented by the Company in R-842590, the entire expenses associated with Richmond No. 9 unit outages had been excluded from the request and also that portion of Southwark #1 & 2 units concerned with the major turbines and boilers overhauls on the six year cycle.) This correction removes those expenses associated with fossil steam units scheduled for retirement. The second adjustment adds the Commission approved normalization for Production Expenses to allow for specific non-reoccurring expenses that are replaced in future years by similar type expenses at other locations on the system. (The items cited in R-842590 were

the Swede St. Dam and the Schuylkill Station City Sewer System. This is the reason why the Swede St. Dam repair expenses in this Test Year has been removed on D-10c of TPH-2.) The third adjustment is to correct the total amount to the time frame of these proceedings for inflation.

It should be noted that the Company re-evaluated the normalized outage expenses for the fossil steam plants using the standard procedure and updated cost experience. However, since the recalculated value was only 0.25% higher than the value approved in R-842590, this claim is based on the previously approved normalized value.

Q. What is the purpose of the adjustment shown on page D-10d of TPH-2?

A. At the time of the Salem No. 1 breaker incident, Public Service Electric and Gas Company (PSE&G) was questioned by the Nuclear Regulatory Commission on the Company's ability to operate and manage a nuclear facility. When PSE&G addressed this question, it took advantage of the timing to perform a complete management review of their procedures and policies with regard to nuclear power operation. PSE&G in conjunction

with Management Analysis Company, a consultant hired for this project, developed an Action Plan for operation and management of their nuclear facilities.

This Action Plan covers seven main areas; Management, Safety, Modifications, Operations, Quality Control, Maintenance, Record Control and Training. The purpose of this extensive examination and development of new procedures for all areas of corporate involvement in the operation of a nuclear facility is to increase the proficiency and efficiency of their organization for now and into the future. The development of these Action Plans are no different than any periodic review taken by Management to address the question "How should we be best operating and managing our facilities into the future." Such reviews are periodically undertaken by management to improve the overall proficiency and efficiency of its organization in specific areas. The Company, therefore, requests a two-year amortization of these expenses.

Q. Would you please explain the basis for the expense adjustment associated with the retirements shown in TPH-2 Page D-11.

A. When the Budget was prepared, expenses were included for the operation and maintenance of Richmond No. 9 Unit, Southwark No. 1 and 2 Units and the internal combustion units scheduled for retirement until their officially predicted retirement date. However, since these units are scheduled for retirement during or shortly after the future test year, those expenses which were included in the Department Budget until retirement will not be incurred during the first full year of rates established in this proceeding. Therefore, the total amount of O&M expenses associated with the operation of these units has been removed from the level of expenses requested in this proceeding.

Q. Mr. Carroll, what is the value and justification for the capacity factors used to calculate the anticipated average generation estimate for the Peach Bottom, Salem and Limerick units on Page D-16?

A. The generation estimates on Page D-16 are based on a 65% Capacity Factor for all the Company's nuclear units. This is consistent with the Company's last rate proceeding, where the Commission accepted a 65% Capacity Factor for the

Salem Units and a 66% Capacity Factor for the Peach Bottom units.

A 65% Capacity Factor also reflects the recent improvements made at the existing plants, e.g., generator rewinding and replacement at Salem and pipe replacement or Induction Heating Stress Improvement to the piping systems at Peach Bottom. In addition, the value of 65% reflects the improvement in Capacity Factor that can be expected in the future since all units will be on an 18 month refueling cycle.

Q. Would you please explain the adjustment to reflect a full year O&M expense for Limerick No. 1 Unit as shown on Page D-18.

A. The non-fuel O&M costs in the Budget do not contain any projected expense for Limerick No. 1. All dollars budgeted to the 517 through 532 accounts for Limerick Station were deferred under the provisions of the Commission's Order at P-840514.

The $63,448,000, shown on Page D-18, represents a full year of non-fuel O&M cost for Limerick No. 1 Unit. This figure was developed from Peach Bottom history. As explained on Page 12 of this

testimony, the units at Peach Bottom and Limerick have very similar operating characteristics and therefore provide a good historical background for projecting the Limerick O&M expenses.

Schedule 3 of this testimony shows the development of Limerick O&M expenses based on the Peach Bottom Station experience. Page 1 shows the historic and projected O&M expenses for Peach Bottom Station for the period of 1981 to 1989. The statistics for 1983 have the unusual expenses for the pipe crack repairs removed and 1984 and 1985 were not used due to the unusual nature of the No. 2 Unit pipe replacement outage. The intent of this schedule is to establish a level of expenses for end of cycle outages and also the level for non-outage related expenses. The non-outage related expenses were then reviewed to determine what portion is unit specific and what portion is for common plant.

This breakdown of non-outage related expenses is necessary since Limerick will be a one unit plant, during the period these rates will be effective, and common plant expenses are not incurred at a 50% level for a one unit plant vs. a two unit plant.

The results of the analysis presented on Schedule No. 3, Page 1 shows that the outage expenses are expected to be $19,400,000 per outage and non-outage money is expected to be $72,570,000. It also shows that 80.2% of the non-outage money is required for common plant and 19.8% is for unit specific items. An adjustment was then made to the total non-outage money to correct Peach Bottom's experience for cooling water and equipment expenses that are unique to Peach Bottom Station. This adjustment results in a non-outage related expense for the Limerick analysis of $71,070,000.

Page 2 of Schedule 3 shows the results of an engineering judgment analysis of the various FERC accounts to determine what portion of these expenses would be incurred if the plant consisted of only 1 unit as opposed to the Peach Bottom history for a 2 unit plant. Each major contributor to the various accounts from 517 through 532 were examined to determine the overall % of common expenses experienced at Peach Bottom that is appropriate at Limerick. This analysis resulted in 88.4% of the Peach Bottom history being applied to Limerick.

Page 3 of Schedule 3 is a summary of the statistics from Pages 1 and 2 used to establish the actual values shown on D-18 of TPH-2. It includes the cost that will be incurred to deliver the cooling water from the Delaware River to Limerick Station during low flow periods. Since all of the Peach Bottom expenses were expressed in 1985$, the costs were then adjusted for inflation to mid-1986 for Test Year purposes. This adjustment includes a 3% annual real growth factor to recognize the trend of increased O&M expenses for nuclear plants.

This approach permitted the Company to use an experienced data base to establish a reliable projection of future O&M expenses that will be incurred at a new nuclear plant on its system with similar operating characteristics.

Q. Mr. Carroll, why did you use historical values for Peach Bottom starting in 1981 rather than for the entire plant's history.

A. The use of history starting in 1981 was used to reflect the 18-month refueling outages, the timing for Limerick fuel cycles, rather than the earlier 12-month fuel cycles. Also, the later

history reflects the changes in O&M expenses due to increased regulation.

Q. Mr. Carroll, please explain the development of the values for total fuel and interchange expense as shown on Page D-21 of Exhibit TPH-2 and the resultant effects on the Company's Energy Cost.

A. The Company's ProdCost Program was used to predict the level of Total Fuel and Interchange Expenses that are expected to be incurred in the two years immediately after the rates determined in these proceedings will be in force. A second computer run was made to determine what would have been the level of Total Fuel and Interchange expenses for the same two year period if Limerick No. 1 was not in commercial operation, but all other conditions on PECO and the other PJM companies did not change. The results of these two computer runs are shown on Page D-21a as the Total Fuel and Interchange Expenses with and without Limerick No. 1 unit.

Q. Please describe more specifically what is the difference between the two totals shown on TPH-2, Page D-21a?

A. Production Cost computer runs were made to determine the fuel and interchange expenses with and without Limerick No. 1 unit in operation. The difference between the two values ($416,636,000) is the fuel and interchange savings available to PECO customers as a result of Limerick No. 1 being included in the rate base and the inexpensive nuclear energy from this unit being available to supply customer load during the two years, July 1, 1986 to June 30, 1988.

Q. Mr. Carroll, why was the analysis performed for a two-year period?

A. This was done to be consistent with the Company's proposed two-year stayout, thereby reflecting our best estimate of the average of costs over the period the proposed rates will be in effect. I should note that we have performed the analysis in the same manner as in our last rate case. Also, our adjustment employs only an annual average fuel savings in developing our test year accounting presentation.

Q. What assumptions have you made in your development of these fuel savings?

A. These assumptions include, but are not limited to:

- o Effective dates of generating plant additions and/or retirements upon PJM.
- o Load requirements of all PJM members.
- o Availability of the units, especially base load units.
- o Fuel Prices.

Changes in any of the above conditions could result in the savings being different from those shown on D-21a. However, the sensitivity of the D-21a results to these assumptions is relatively less in a savings study such as this because the changes would be approximately the same for both cases (with and without Limerick No. 1 unit). The exception to this, of course, is the input data for Limerick No. 1 Unit.

Q. What capacity factor was projected for Limerick No. 1 unit in the study that developed the savings shown on TPH-2, Page D-21a?

A. In the study period, Limerick was projected to experience a 64.6% Capacity Factor.

Q. Mr. Carroll, do you believe that the fuel savings which you have developed associated with the commercial operation of Limerick 1 are a reasonable estimate of such future savings and should be used by the Commission in this proceeding?

A. Yes, I do.

Q. Mr. Carroll, in preparing the Company's Production O&M expenses for this filing, what actions were taken to insure that the expenses contained in Exhibit TPH-2, Pages B-10 and B-11 are normalized expenses?

A. The expenses shown on Pages B-10 and B-11 for the Production O&M expenses are the result of the budgeting process within the Electric Production Department (EPD). This budgeting process is designed to review all budgeted expenses in comparison to normalized trends. The individual Responsible Areas within the Electric Production Department submit budgets categorized into three areas: routine; non-outage specific and outage related expenses. All three of these categories are then summarized and compared to the trended level of expenses developed from history. Any

deviations from this trend must be explained and defended. The totals for the Department are then again summarized and compared to the trended total developed from history. It is the purpose and goal of these procedures to submit a budget for the Electric Production Department which is in agreement with the normalized expenses which the Department has supported in the previous Rate filings and is consistent with the revenue generated to support the Electric Production Department's Operating and Maintenance Expense requirements.

Deviations from this trend are the basis for the D-10 adjustments explained in this testimony, as well as the basis for the variations of specific FERC account as explained in Volume II-D-1.

Q. Mr. Carroll, are there any other comparisons you have made to demonstrate that the level of Power Production expenses requested in these proceedings are a normalized level of expense?

A. Yes, I have prepared Schedule 4 attached to this testimony. This schedule shows the Total Power Production Expenses (less Fuel) that the Company is requesting in these proceedings, adjusted for

the corrections of D-10 and D-11 in TPH-2. Also shown in this schedule, are the expenses predicted to be incurred in the same FERC accounts for the years 1986 through 1989. These statistics show that the amount requested (as shown on pages B-10 and B-11 of TPH-2) is less than the average of the next four years by over 8%.

Due to the adjustment on D-11 of TPH-2, the test year values are after the retirement of Richmond, Southwark and the selected Combustion Turbines and do not include the expenses for Limerick Station. The years 1986 through 1989 have been assembled on a comparable basis.

Q. Does this conclude your testimony?

Y. Yes, it does.

APPENDIX A

Testimony of John J. Carroll

Q. Please summarize your responsibilities in the various positions you have held with Philadelphia Electric.

A. While assigned to the Station Operating Department from 1952 to 1960, I held non-supervisory positions at several generating stations operated by Philadelphia Electric. My work in these stations included the testing of plant performance and work on the instrumentation and control systems within the stations. While working in the Economy Division from 1960 to 1974, I was responsible for the development of incremental costs used to load generating equipment for maximum economy, the development of budgets and forecasts of generation, fuel requirements and costs, interchange accounting practices and procedures, and the development of reserve requirements rules and procedures for rating capacity. Some of the work was done for Philadelphia Electric in conjunction with the PJM Interconnection. In 1974, I was appointed Engineer-In-Charge of the Cost Section. This section develops Philadelphia Electric's budget for fuel, generation, interchange, and operation

and maintenance expenses. It also monitors the actual expenditures and sources for power and compares these with budget values and investigates the reasons for any variation. The Cost Section also develops future production requirements and O&M expenses for outage planning and changes in the operated mode of the power production system. The Cost Section has the responsibility for forecasting and monitoring the expenses incurred by the Electric Production Department and for providing management with the necessary information for economic operation of the Department. As Engineer-In-Charge, I had full responsibility for the implementation of the duties outlined above. In my current position as Staff Engineer, I have responsibility for special studies and projects within the Electric Production Department, including plant performance evaluations, regulatory matters, and economic analyses.

Q. What are your professional affiliations?

A. Since 1952, I have been a member of The American Society of Mechanical Engineers. I have served as a member and chairman of various subcommittees

and task forces of the PJM Interconnection as the PE representative on such groups.

Q. Have you testified in any previous rate proceedings before the Pennsylvania Public Utility Commission?

A. Yes. I presented testimony in Philadelphia Electric Company's most recent electric rate case, R-842590, in support of production operation and maintenance expense, fuel inventory claims and various expense adjustments. I also testified concerning these same matters in the Company's seven preceding electric rate cases at R-822291, R-811626, R-80061225, R-79060865, RID 438, RID 295 and RID 129. My testimony in these cases also included the preparation and presentation of computer based generation reload studies to be used in determining normal Electric Production costs, capacity factor analysis in support of claimed normal or estimated future plant operating levels (including nuclear plants), the presentation and support of Philadelphia Electric's Six Year Preventive Maintenance Program for fossil generating plants and of its twelve and now eighteen month outage maintenance program for Peach Bottom Unit 2 and

3, explanations of PJM Interchange Accounting and costs and of the costs and circumstances associated with purchasing power from non-PJM sources. In addition to the above, I testified for the Company in M-830453, et al and I-840381 concerning O&M expenses, Capacity Factors for nuclear and fossil units, maintenance scheduling, fuel and interchange costs and replacement power expenses.

Schedule 1
Development of Normalized Outage Costs
Nuclear Plant Outage

Values from R-842590 - expressed in 1984$

Peach Bottom Station	$11,726
Salem Station per Unit	5,184

The Limerick Values in 1985$ is from Schedule 3 $12,900

Inflation Adjustment for Future Test Year

1985	1.0525
to June 1986	1.032
Applied to Peach Bottom and Salem	1.0862
Applied to Limerick	1.047

1.032 + 1/2 1.03 (Real Growth)

Future Test Year Normalized Outage Expenses

Peach Bottom Station	$11,726 x 1.0862	= $12,737
Salem Station	$ 5,184 x 2 x 1.0862	= $11,262
Limerick Station	$12,900 x 1.047	= $13,506

Schedule 2
Development of Normalized Outage Costs
Philadelphia Area Fossil Stm. Units
D-10b

	$1,000	
Presentation in R-842590	$21,611	(1984$)
Commission Ordered Inflation Adjustment to 4.2%	- 1.06 x 1.042	
Commission Approved Value	21,244	
Correction to Remove Swk. #1 & 2	(467)	
Commission Approved Normalization	147	
Corrected Value	$20,924	(1984$)
Inflation Adjustment to Future Test Year $ 1.0525 for 1985 1.032 to June 1986	x 1.0862	
Normalized Outage Expenses	$22,728	

Schedule 3

Development of Limerick O&M Expenses as Function of Peach Bottom Costs

An analysis of Peach Bottom's historic and projected costs for the period 1981 through 1989 (less 1984 and 1985) was used to determine what level of expenses would be incurred in the future for the Operation and Maintenance of Limerick Station.

Peach Bottom O&M Expenses (Total Station) Expressed in 1985$

Non-Outage O&M Expenses $1M

Year	Total	Common	Unit Specific	Outage Expenses
1981	58.9			18.8
1982	63.0			20.1
1983	68.0			20.3
1986	82.2	65.6	16.6	32.2
1987	80.8	65.0	15.8	27.1
1988	77.4	62.4	15.0	18.8
1989	77.7	62.2	15.5	37.6
Average	72.57	63.8	15.73	174.9 for 9 Outages $19.4/Outage
1986-89	79.52	63.8	15.73	

% Applied to Various Components

$$\text{Common} = \frac{63.8}{79.52} = 80.2\%$$

$$\text{Unit Specific} = \frac{15.73}{79.52} = 19.8\%$$

Total Peach Bottom Costs Applicable to Limerick.

Non-Outage = $72.57 - 1.5 = $71.07

$1.5 = Average Cost of Cooling Water Cost plus O&M for Forced Draft Cooling Tower Lift Pumps and Fans

Limerick O&M Study
Analysis of Peach Bottom Expenses
for Determination of 1 Unit Costs

Account	Description	% Allocated to 1st Uni
517	Oper. Supv. & Engrg.	95%
519	Coolants & Water	
	Water	0%
	Make-up Demineralizer & Raw Water	
	Demineralizer Plant	60%
	Waste Water Treatment Plant	
520	Steam Expense	
	Health Physics Expenses	75%
	Waste Disposal Expense	75%
	Plant Labor - Steam Generator	
	Auxiliary Boiler (excl. Fuel)	100%
	Misc. Items	
523	Electric Expense	
	Plant Labor Electric	100%
	Supplies & Expense	
	Lubricants & Generator Gas	90%
	Chlorine	
524	Misc. Nuclear Power Expense	
	Utility & Housecleaning	
	Plant Security	95%
	Computer Expenses	
528	Maint. Supv. & Engrg.	90%
529	Maintenance of Structures	100%
	Buildings & Structures	
	Building Service Equipment	
	Yards, Siding, Bulheads & Berms	
	Common Ventilation Equipment	
530	Maint. of Reactor Equipment	100%
	Common Fuel Handling Equipment	
	Common Radioactive Waste Systems	
	Computer Maintenance	
	Common Compressor & Nitrogen Equip.	
531	Maint. of Prime Movers & Generators	
	Cooling Towers	0%
	Diesels & Generators	100%
	Station Light & Pwr. Common Equip.	100%
532	Maint. of Misc. Nucl. Plant Equip.	
	Sewage Plant	
	Fire Equipment	100%
	Raw Water System	
	Health Physics - Material & Vendor	75%
	Health Physics - Labor	75%

Schedule 3

Development of Limerick O&M Costs
$1,000,000 in 1985$

Item	P. B. Costs	Factors	Lim. No. 1 Costs
Common Plant	$71.0	.802 x .884	$50.4
Unit Specific	$71.0	.198 x .5	7.0
Cost of Water	-	-	3.2
Total			$60.6

Total O&M (Non-Outage)

1985$		Inflation for 6 mo. of 1986	
$60.6	x	1/2 (1.064 + 1.03)	= $63.448

Inflation = 6.4%
Real Growth = 3%

Outage

$19.4 x 2/3 Outage/Year = $12.9 Normalized

$12.9 x 1.047 = $13.506

Schedule 4

Comparison of Power Production Expenses (Less Fuel) Future Test Year Vs. Next Four Years $1,000

Acct. No.	Future Test Year	1986	1987	1988	1989	Avg. 1986 to 1989
500	15,217	14,548	15,470	16,350	17,376	15,936
502	38,124	38,383	41,077	43,838	46,401	42,425
504 *	(7,634)	(7,833)	(8,327)	(9,011)	(9,761)	(8,733)
505	7,682	6,080	6,521	6,960	7,328	6,722
506	13,356	12,916	13,675	14,541	15,257	14,097
507	15,065	15,068	15,462	15,884	16,335	15,687
510	9,599	9,799	10,762	11,556	12,564	11,170
511	9,042	6,215	5,969	6,520	6,320	6,256
512	64,728	51,711	61,574	58,704	64,974	59,241
513	18,284	13,542	14,932	15,540	15,488	14,876
514	3,552	2,986	3,187	3,402	3,385	3,240
Sub-Total	187,015	163,415	180,302	184,284	195,667	180,917
Adj. D-10b	4,028	-	-			-
D-10c	(15,750)	-	-			-
D-11	(7,513)	-	-			-
Adj. Sub-Total	167,780	163,415	180,302	184,284	195,667	180,917
517	12,727	12,472	12,214	12,673	14,217	12,894
519	1,138	1,161	1,358	1,448	1,668	1,409
520	18,798	22,791	21,526	19,209	26,892	22,605
523	2,356	2,546	2,458	2,598	3,002	2,651
524	39,955	41,673	40,489	45,807	49,444	44,353
525	87	85	81	77	68	78
528	16,795	17,609	16,232	16,642	22,008	18,123
529	3,715	3,789	4,028	4,061	5,266	4,286
530	16,884	22,932	21,072	20,141	27,842	22,997
531	10,049	10,655	11,904	11,834	11,796	11,547
532	5,448	5,854	6,086	5,646	6,607	6,048
Sub-Total	127,952	141,567	137,448	140,136	168,810	146,991
Adj. D-10a	7,145	-	-	-	-	-
D-10c	(45)	-	-	-	-	-
Adj. Sub-Total	135,052	141,567	137,448	140,136	168,810	146,991

* Less Fuel

Schedule 4

Comparison of Power Production Expenses (Less Fuel) Future Test Year Vs. Next Four Years $1,000

Acct. No.	Future Test Year	1986	1987	1988	1989	Avg. 1986 to 1989
535	404	417	455	732	782	596
536	368	392	418	1,871	1,997	1,169
537	1,170	1,250	1,344	1,583	1,688	1,466
538	230	241	257	275	293	266
539	424	456	470	590	632	537
540	1	1	1	1	1	1
541	540	570	633	686	744	658
542	210	189	202	242	230	215
543	247	250	267	285	304	277
544	3,133	2,080	1,650	1,914	1,875	1,880
545	147	153	163	213	227	189
Sub-Total	6,874	5,999	5,850	8,392	8,773	7,254
546	1,029	1,032	1,053	1,109	1,189	1,096
548	1,327	1,089	1,032	1,106	1,170	1,099
549	1,479	1,510	1,580	1,687	1,793	1,643
550	1,140	-	-	-	-	
551	629	644	677	722	778	705
552	233	229	225	240	254	237
553	6,221	4,222	4,231	4,241	4,370	4,266
554	102	102	107	115	122	111
Sub-Total	12,160	8,828	8,905	9,220	9,676	9,157
Adj. D-11	(3,043)	-	-	-	-	
Adj. Sub-Total	9,117	8,828	8,905	9,220	9,676	9,157
556	6,022	6,256	6,736	7,312	7,919	7,056
557 *	30	29	31	33	35	32
Sub-Total	6,052	6,285	6,767	7,345	7,954	7,088
Total Pwr. Prod	324,875	326,097	339,272	349,377	390,880	351,407

* Less Fuel

ORIGINAL

Statement No. 23

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY
DOCKET NO. R-850152

DIRECT TESTIMONY OF

GUY A. SILEO

TAX LEVELS
AND TAX ADJUSTMENTS

September 1985

SEP 27 1985

Taxes Division. My initial position in the Taxes Division was as a Junior Tax Accountant, later being promoted to Senior Tax Accountant and Assistant Manager of the Taxes Division. In 1980, I assumed my present position as Manager of the Taxes Division.

Q. What are your responsibilities as Manager of the Taxes Division?

A. Taxes Division has overall tax responsibility for the Company and its subsidiaries at the federal, state and local levels. This responsibility includes tax planning and research, collection and preparation of tax accounting data, preparation and filing of tax returns, and settlement of returns and tax claims. Essentially, my responsibility encompasses research and planning, accounting, compliance, return preparation and then filing.

Q. Please describe in greater detail your activities as Manager of Taxes Division.

A. I have overall responsibility for the preparation of the tax portion of the Company's budget and forecast, for all tax accruals and for the Company's various tax returns, including their presentation to senior management for signature. Under my direction, the necessary accounting data is collected from the Company's accounting divisions for the preparation of tax returns and the accompanying schedules. I participate in all audits, requests for

Technical Advice, appeals, and litigation concerning any of the Company's tax returns, including the preparation and presentation of documentation in support of the Company's tax computations and application of tax policy. My responsibilities also include the analysis of the tax aspects of various proposed Company actions, the interpretation and review of proposed and enacted tax legislation to determine its impact on Company operations and the continuing review of the Company's tax policy.

Q. Have you testified as to tax matters in any previous proceedings?

A. Yes. I have presented testimony before the Pennsylvania Public Utility Commission as to tax matters in the Company's last three electric rate cases at dockets R-811626, R-822291, and R-842590 as well as in the Limerick Generating Station investigation at I-80100341.

Q. What exhibits and schedules in this proceeding are you responsible for?

A. I am responsible for the substantive tax aspects of Exhibits TPH-1 and TPH-2, Schedules D-1, D-7, D-8, D-9, D-14, and D-20, for the development of book tax expense shown on B-14 and B-15, and the computation of the effective income tax rate on page B-18, for the development of the Accumulated Deferred Taxes on page B-16 and for the development of taxes associated with proposed rates on page A-4.

Q. Mr. Sileo, would you review the tax computations on pages B-14, B-15, B-16 and B-18 of TPH-1 and TPH-2?

A. Page B-14 of TPH-1 shows the total actual taxes charged to electric operations based on historic information, while the same exhibit in TPH-2 shows total budgeted taxes in the future test period. The purpose of the computation on page B-15 of each exhibit is to show the adjustments to book operating income that are necessary to develop the federal income taxes shown on page B-14. The accumulated deferred income taxes, shown on page B-16 of each exhibit, are based on the tax deferral for electric plant in service at the end of each test period and an allocated portion of such taxes related to common plant. The amount developed on page B-16 for electric operations is deducted from rate base on page A-2. The calculation on page B-18 develops the total federal and state effective income tax rate to be applied to incremental changes in taxable income under pro forma proposed rate conditions. The computation reflects the statutory federal rate of 46% and the pre-1971 statutory Pennsylvania rate of 7.5%. Changes in the Pennsylvania rate since 1970 are reflected in the State Tax Adjustment Clause (STAC) rather than in base rates.

Q. Mr. Sileo, would you briefly explain the tax depreciation and normalization adjustments shown on D-7 and D-8 of TPH-1 and TPH-2.

A. Yes, the purpose of D-7 is to reflect a full year of tax depreciation calculated on a year-end plant base under pro forma conditions. This is accomplished by adjusting the tax depreciation used in the budget to a ratemaking level.

The purpose of D-8 is to reflect a full year of normalized taxes calculated on year end plant under pro forma conditions by adjusting the budgeted tax deferrals to a ratemaking level. In accordance with prior PA PUC findings, the normalized deferred federal tax is calculated at 46% of the excess tax depreciation over straight-line depreciation using a year end tax base.

Q. Mr. Sileo, would you briefly address the adjustments on pages D-1, D-9, and D-14 of TPH-1 and TPH-2?

A. The adjustment on page D-1 of TPH-1 and TPH-2 removes the Pennsylvania Realty Tax (PURTA), and portions of the gross receipts, capital stock, and corporate net income taxes from the tax claim in this rate case. A like amount of revenue is also removed since the applicable taxes are collected through the STAC mechanism and not base rates.

Page D-9 of TPH-1 and TPH-2 contains the adjustment necessary to reflect the income tax effects on interest charges associated with test year end rate base, in accordance with past Pennsylvania PUC practice.

The adjustment to the Federal Old Age Benefit (FICA) tax expense found on page D-14 of TPH-2 is necessary to

annualize the effects of the FICA wage base and rate increases on January 1, 1986. In a similar fashion, the adjustment on page D-14 of TPH-1 annualizes the effects of the FICA base and rate increases on January 1, 1985.

Q. Mr. Sileo, has the Company annualized the amortization of the Investment Tax Credit to reflect a test year-end level as was ordered in your last rate case?

A. Yes we have. Under pro forma proposed rates the entire amount of ITC carryover associated with plant in service at 6/30/86 can be utilized. Accordingly, Page D-20 of TPH-2 reflects a full year of such ITC amortization. In addition, the adjustment on Page D-20 reflects a full year of amortization associated with ITC on Limerick progress payments previously utilized by the Company but not amortizable until the plant is in service.

In a similar fashion, page D-20 of TPH-1 reflects a full year of amortization on the ITC carryover associated with plant in service at 6/30/85 and the amortization associated with Limerick.

Q. Mr. Sileo, are you familiar with the Pennsylvania Supreme Court's recent decision regarding the normalization of income taxes associated with liberalized depreciation?

A. Yes, I am.

Q. Does the Court's decision affect the Company's claimed tax expense in this rate proceeding?

A. No, it does not. First, we have made no claim for normalized state deferred income taxes associated with liberalized depreciation in this case. Second, Pennsylvania Power Company did not make an election in 1970 to normalize federal deferred income taxes and therefore is not required to normalize these tax benefits in order to claim them as deductions on its federal income tax return. PECO did make the election in 1970. This election is irrevocable, and PECO is therefore requried to normalize federal deferred income taxes. Consequently, the Supreme Court's decision does not apply to PECO.

Q. Mr. Sileo, has the Company included in this rate filing the amortization and rate base deduction for the Salem 2 tax benefit transfer that has been ordered in the Company's last rate case at R-842590?

A. No, we have not.

Q. Can you explain why?

A. Yes, in December, 1981, PECO entered into an agreement in which it sold certain tax benefits associated with Salem 2 to Hercules Corporation for $129.7 milion. $53.7 million of this amount was paid up front, and the remainder over a 15-year period. This up front payment consisted of Investment Tax Credit, Deferred Income Tax, and a "make whole" payment of $6.9 million. In the Company's last rate proceeding, the Commission adopted an OCA proposed

adjustment which characterized the $6.9 million listed above as PECO's "profit" on the sale and required the Company to give the $6.9 million to ratepayers over the remaining life of the plant. As set forth below, I believe this adjustment is inappropriate and should be reconsidered.

First, and most importantly, the $6.9 million is not "profit". Under the Internal Revenue Code, the Company would generally have received the Salem 2 tax benefits over 10 years, and these benefits would be flowed through to ratepayers over the life of the plant. The $6.9 million payment reflects the time value of money difference associated with the receipt of these tax benefits over 15 years under the terms of the sale, and simply placed the Company in the same cash flow position it occupied before the sale. The $6.9 million payment is not profit; it is compensation to PECO for the lost time value of money.

Second, since the Salem 2 tax benefits are flowed through to ratepayers over the life of the plant, whether the Company receives the tax benefits over 10 or 15 years should be irrelevant in establishing rates. The Company's proposal recognizes this by treating ratepayers in the same manner both before and after the sale, i.e., Salem 2 tax benefits are received over the life of the plant. The effect of the Commission's position on this issue, on the other hand, is to take from the Company and give to

ratepayers, the time value difference in receiving the Salem 2 tax benefits over 15 years under the terms of the sale as compared to 10 years under the Internal Revenue Code. This adjustment thereby leaves the Company in a worse position than before the sale and places the ratepayer in a better position. Thus, the $6.9 million time value of money payment shold not be given to ratepayers as ordered by the Commission in the Company's last rate proceeding.

Finally, this result is particularly inapproporiate in view of substantial benefits ratepayers received from the sale. The $53.7 million initial proceeds of the sale in 1981 substantially exceeded the $8 million tax benefits the Company would have received in 1981 from Salem 2 without the sale. The difference of $45.7 million represents cost free capital. Had the Company raised such capital in the market, it would have cost the ratepayer approximately 18% annually, the prevailing rate in December 1981, or $8.2 million a year.

For these reasons, the Company respectfully requests that the Commission reconsider its adjustment in this proceeding.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

DIRECT TESTIMONY OF GUY A. SILEO

Q. Please state your name and business address.

A. My name is Guy A. Sileo and my business address is 2301 Market Street, Philadelphia, Pennsylvania 19101.

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

A. I am Manager of the Taxes Division of Philadelphia Electric Company.

Q. What is your educational background?

A. I graduated from Widener University with a Bachelor of Science Degree in Business Administration. In 1972, I received a Masters of Business Administration Degree from Drexel University.

Q. Are you a member of any professional organizations?

A. I am a member of the following organizations: Edison Electric Institute, serving on its Committee on Taxation and Subcommittee on Tax Legislation; the Tax Executives Institute serving on the Institute Board of Directors; and the Pennsylvania Chamber of Commerce, serving on its Tax Committee.

Q. Please describe your experience with Philadelphia Electric Company.

A. I joined Philadelphia Electric Company in 1950, progressing through various positions in the Customer Accounts Division and computer system analyses and programming in the Company's Computer Division until 1965, when I joined the Taxes Division. My initial position in the Taxes Division

ORIGINAL

Statement No. 24

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. 850152

DIRECT TESTIMONY

OF

WILLIAM F. SUNDERMEIR

CLASS COST ALLOCATION

AND UNIT COST STUDY

SEP 27 1985

September, 1985

Direct Testimony of William F. Sundermeir

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

A. William F. Sundermeir, 2301 Market Street, Philadelphia, Pennsylvania.

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

A. I am employed by Philadelphia Electric Company. I am the Supervisor in charge of the Cost and Load Analysis Section of the Rate Division.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Mechanical Engineering from Drexel University in 1956.

Q. Describe your work experience with Philadelphia Electric Company.

A. Immediately upon graduation from Drexel University, I spent approximately four years in generating station design work in the Mechanical Engineering Division. In 1960, I was transferred to the Station Operating Division where I was assigned to various engineering responsibilites in an electric generating station. In 1962, I was transferred to the Rate Division of the Finance and Accounting Department. From October 1962 until January 1972 my assignments included rate design, the preparation of data for rate filings and the development of load characteristic data for each of the Company's classes of service. In January 1972, I was appointed to my present position as the Supervisor in

charge of the Cost and Load Analysis Section of the Rate Division.

Q. Please describe the primary duties of the Cost and Load Analysis Section.

A. The primary responsibilities of this section are to develop cost to serve studies and the class load characteristic studies that are required for the cost to serve studies. Both of these studies are basic requirements for proper rate design. This section is also responsible for the design of rates for the large commercial and industrial customers. In addition, this section is responsible for the preparation of rate filing data that are related to cost to serve or load characteristics.

Q. Could you further describe your responsibilities and accomplishments?

A. I am responsible for defining the data requirements and the scheduling of the Company's load research program. This program must be designed to satisfy the data requirements of the Company and the regulatory commissions. Also, I was responsible for the design and implementation of an experiment to determine the effects of a rate for residential electric space heating service that recognized load factor.

I have written several reports on load studies which have been printed in the annual report of the Load Research Committee of the Association of Edison

Illuminating Companies. In conjunction with this Committee, I have participated in task force studies on coincidence factor - load factor relationships and residential class load factors. I have also assisted in conducting workshops on various aspects of load research. These workshops were conducted under the direction of the Load Research Committee of the Association of Edison Illuminating Companies and were attended by representatives from utilities throughout the United States.

In August 1982, I made a presentation to the Northeast Regional Load Research Conference of the Association of Edison Illuminating Companies on the use of load research data in costing and rate design. This presentation included a description of the methodology used to develop large commercial and industrial rates.

In addition, I have participated in the preparation of a report by the Franklin Institute Research Laboratories for the National Science Foundation. This report was on the Implications of Residential Solar Space Conditioning on Electric Utilities.

Q. Mr. Sundermeir, have you testified in any previous regulatory proceedings?

A. Yes. I presented testimony in the Commission's investigation at Docket No. L-810060 concerning the implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). I have also

testified before the Maryland Public Service Commission in regard to rates filed by Conowingo Power Company for the purchase of energy from cogenerators and small power producers. In addition, I have testified before this Commission in the hearings relative to the Company's request for a gas rate increase in 1981 (Docket No. R-811719), a steam rate increase in 1982 (Docket No. R-822101) and two electric rate increases in 1983 and 1984 (Docket Nos. R-822291 and R-842590).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to introduce and explain the Company's class cost allocation and unit cost study and the load characteristics used to allocate demand and energy related costs to classes of service.

Counsel:

I ask that there be marked as Exhibit WFS-1 a document entitled Allocation of Costs and Rates of Return By Classes of Service 12 Months Ended June 30, 1986.

Q. Mr. Sundermeir, was Exhibit WFS-1 prepared by you or under your supervision and direction?

A. Yes it was.

Q. Please describe the contents of Exhibit WFS-1.

A. Exhibit WFS-1 contains ten sections preceeded by an introduction that briefly explains the cost allocation methodology and a description of the contents in each of the ten sections. The introduction also includes a list of the rates included in each of the classes of service

shown in the cost study and a description of special studies used in preparation of the cost study. All of the data included in this exhibit are for the twelve month period ended June 30, 1986 except for the load data presented in Section VIII. I will discuss the load data later in my testimony. The data for the twelve month period ended June 30, 1986 are budget data for that period that have been adjusted to reflect the adjustments shown in Exhibit TPH-2.

Q. Please summarize the more important parts of Exhibit WFS-1?

A. Yes. Page 6 is a summary of the results of the cost allocation for the twelve month period ended June 30, 1986. The details of this allocation study are presented in Section II. Page 6 shows the rates of return by classes of service under present rate schedules (line 31) and the rates of return that would be obtained in that period if the rates proposed in this filing were in effect (line 33). Section IV shows all of the allocation schedules that were used in the alloction of costs in Section II.

Section VI shows the development of the unit costs for each of the classes of service. These unit costs are used to develop the cost curves shown in Section VII. The curves in Section VII show a comparison between costs and revenues for residential and demand/energy rate schedules. Section VIII shows load curves for the major classes of service for the average of the day of system

peak in each of the four summer months (June through September) in 1984. This section also includes demand, energy, load factor and coincidence factor data for the major classes of service and a description of the source and age of the load data used to develop the class load curves.

Section IX contains the most recent overall system loss study. Section X shows a summary of the results of a cost study using the average and excess allocation method.

Q. Please describe the allocation methods used in the cost allocation.

A. Cost by accounts or by functionalized accounts are allocated to classes of service in accordance with the factors that primarily influence the cost occurrence. For example, production and transmission plant and the related expenses are allocated to classes of service on the basis of the average contribution of each class to the hourly system peaks in each of the four summer months (June through September). Production and transmission plant must be designed to meet the maximum demand requirements imposed on the system by the customers; therefore, it is appropriate that these costs should be allocated on the basis of contribution to those peak demands.

Q. Would you describe other important allocations shown in Exhibit WFS-1?

A. Yes. Distribution plant and expenses are a function of both demand related and customer related costs and, when

possible, some costs are directly assigned. All customer costs are allocated to classes of service on the basis of the number of customers in each class. All distribution costs that are not customer related are classified as demand related since costs in excess of the customer costs are incurred to satisfy the demand requirements of the customers. Demand related distribution costs are allocated to classes of service on the basis of noncoincident class peaks since the distribution facilities must be designed to satisfy the maximum demand requirements in areas regardless of the time of occurrence of such demand. Fuel and other energy related expenses are allocated to classes of service on the basis of the energy generation requirements of each class. Expenses that cannot be categorized as being demand, energy or customer related are generally allocated on the basis of composite schedules that are developed from related cost data. There have been no significant changes in the cost allocation method used in Exhibit WFS-1 from those adopted by the Commission in RID 295, RID 438, R-79060865, R-80061225, R-811626, R-822291 and R-842590.

Q. Mr. Sundermeir, you have testified that you allocate production and transmission plant to each class of service on the basis of the average contribution to system peak of each class on the day of system peak in each of the four summer months. Would you explain your rationale for using this allocation method?

A. Yes. Since 1958, Philadelphia Electric Company has been classified as a summer peaking company, since the summer system peak is significantly higher than the winter system peak. The summer system peak has historically occurred in any of the four summer months of June through September primarily depending on the occurrence of hot weather. In addition, class load characteristics may change from one month to another due to factors other than weather. For example, schools may be in session in June and September while industrial load may be affected by vacation schedules in July and August. Also, the clock hour in which the peak occurs can have an effect on the allocation. In order to provide stability to the allocation of the production and transmission plant and expenses the average of the data for the day of system peak in each of the four summer months is used. In 1984, these peaks occurred on June 13, July 16, August 9 and September 14.

Q. You stated earlier in your testimony that the load data in Section VIII of Exhibit WFS-1 is for the four summer months in 1984. Did you use these data to allocate costs?

A. No. The curves and tables in Section VIII are for illustrative purposes only since at the time of this filing these are the latest available actual data. For the cost allocation these data were adjusted to reflect the budgeted sales in the twelve month period ended June 30, 1986.

Q. How did you make the adjustment from actual data to the future test year?

A. The actual demand data are adjusted in accordance with the ratio between annual sales in the test year and actual sales in calendar year 1984. In other words, it is assumed that there is a constant relationship between demands and annual energy use between the actual period and the test year.

Q. Why did you use annual energy use instead of monthly energy use to adjust the demand data to the test year?

A. The relationship between maximum demands and energy use in a given month is significantly dependent on weather conditions in the month. This is particularly true in the summer months from which most of the demand data used in the cost allocation are obtained. A given month with high energy use may have lower maximum demands than the same month in another year with lower energy use; therefore, I believe that the assumption that the demand in a given month from one year to the next is directly related to the energy use in those months is not a good assumption. I believe that annual energy use is a more appropriate basis for the adjustment of demands since it provides stability to the calculation and is less volatile than the use of monthly data.

Q. Were the load data for 1984 based on actual data for those years?

A. Actual data were used to develop all class loads except

the residential and small commercial and industrial classes. The development of load data for these classes was based on the most recent load survey data. The load survey data for these classes are adjusted to reflect the customer distribution and the actual weather conditions for the actual days that the load data are developed.

Q. Are any of the costs that you have developed used directly in the design of any of the proposed rate schedules?

A. Yes. In accordance with the Commission's Order in RID 438, the pricing of Rate HT and PD is strictly developed on the basis of cost data. The customer charges in these rates are obtained directly from the unit cost study. The energy pricing is established in accordance with the slopes of the cost curves in the designated price blocks, and the demand charge is established on the basis of the remaining total revenue requirement that is not recovered by the customer or energy prices. The method used in this filing is exactly the same as the method approved in the last five rate proceedings.

Q. In response to the last question, you indicated that you used cost curves to establish energy pricing for Rates HT and PD. Could you briefly describe how those curves are developed?

A. Yes. The curves are developed from the unit cost data shown in Section VI. It can be seen that the cost curves are a plot of the hours' use of maximum demand versus cost expressed in dollars per kilowatt. The cost curve is the

sum of three cost components - the customer component, the energy component and the demand component. The customer component is constant for all hours' use of demand, while the energy component increases directly with the increase in hours' use of demand. The demand component is calculated based on the known relationship between coincidence factor and load factor. Use of this relationship in establishing the demand component of cost recognizes that customer loads become more coincident as load factor increases.

Q. Mr. Sundermeir, in the Commission order in the last Philadelphia Electric Company rate case (Docket No. R-842590), the Company and the Trial Staff were ordered to prepare and submit a study of the cost to serve SEPTA and AMTRAK. Have your prepared such study?

A. Yes. A cost to serve study for both SEPTA and AMTRAK is shown in Exhibit WFS-1.

Q. What are the results of this study?

A. As can be seen on page 6b of Exhibit WFS-1, the rates of return for SEPTA and AMTRAK on existing Rate HT are 7.86% and 7.55%, respectively. The system average rate of return is 6.39%. Under the proposed separate rates for SEPTA and AMTRAK, the rates of return for both of these customers are 12.70%. This is equivalent to the system average rate of return at proposed rates. Under proposed Rate HT the rates of return for SEPTA and AMTRAK would be 14.36% and 14.15%, respectively.

Q. Please describe how the costs for SEPTA and AMTRAK were determined?

A. With the exception of the distribution costs, the costs have been allocated or directly assigned to the railroads and railways in a manner similar to that used in assigning costs to all classes of service shown in Exhibit WFS-1. The distribution costs were directly assigned to the railroads based on an analysis of the actual distribution system used to serve the railroads.

Q. Could you describe how the analysis of the distribution system was done?

A. Yes. A detailed analysis was made of the number of poles, the size and length of cable (both aerial and underground) and conduit and the number of manholes in all distribution circuits providing service to the railroads. The actual cost of the manholes was available. These costs were allocated to the railroads in proportion to the number of conduits in the manhole. The costs for the other equipment were based on average installed costs in the years in which the equipment was installed. In cases where equipment was used to serve railroad load plus other load, the costs were allocated to the railroads in accordance with the ratio of railroad load to total load.

Q. Has the procedure that has been used to determine the costs for the railroads and the resulting rate of return been reviewed by the Trial Staff as requested in the Commission Order at Docket No. R-842590.

A. Yes. On April 24, 1985, representatives from the Company, including myself, met with the Trial Staff to describe the methods used to assign and allocate costs to the railroads and to review the results of this study. The Trial Staff indicated that the method used for the study and the results seemed reasonable.

Q. Mr. Sundermeir, does that conclude your testimony?

A. Yes, it does.

PECO Statement No. 25

ORIGINAL

RECEIVED

SEP 27 1985

SECRETARY'S OFFICE
Public Utility Commission

Pennsylvania Public Utility Commission

v.

Philadelphia Electric Company

Docket No. R-850152

Direct Testimony

of

Warren H. Smith

Plant In Service Accounting

Procedures and Controls

September 27, 1985

P-2

Direct Testimony of Warren H. Smith

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

A. Warren H. Smith, 2301 Market Street, Philadelphia, PA 19101

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

A. I am Manager of the Plant Accounting Division of Philadelphia Electric Company.

Q. What is your educational background?

A. I received a Certificate in Accounting from Temple University in 1958.

Q. Please describe your work experience with Philadelphia Electric Company.

A. I was employed by Philadelphia Electric Company in 1951 as a junior clerk in the Plant Accounting Division. Initially, I was responsible for operating and producing reports on IBM data processing equipment. After advancing to senior property clerk, I maintained the control ledgers of the Division, analyzed construction work orders to determine costs by property units for inclusion in the continuing property records, and participated in special cost studies.

In 1961, I transferred to the Taxes Division. As a junior tax accountant, I was responsible for the computation of book and tax depreciation and investment tax credit, preparation of tax returns and the analysis of new tax legislation. In 1965, I transferred to the Financial Division, where, as a senior analyst, I was responsible for

computing book and tax depreciation, and assisting in the preparation of depreciation life studies and data for the Company's 1968, 1970 and 1971 rate filings.

In 1972, I transferred back to the Plant Accounting Division as a senior technical assistant. In 1973, I was appointed General Supervisor of Plant Accounting. I was appointed Assistant Manager in 1975 and in 1978 I was appointed to my current position of Manager of Plant Accounting.

Q. Please describe in detail your responsibilities as Manager of the Plant Accounting Division.

A. My primary responsiblity is to account and maintain the detailed records for the original cost of plant in service, construction work in progress, plant held for future use and nuclear fuel in the process of refinement, conversion, enrichment and fabrication. I am also responsible for the computation of all book and tax depreciation and additions to plant which qualify for the investment tax credit as well as for producing all utility plant related reports necessary to support tax returns, the mortgage indenture, insurance policies and billings for relocation of facilities. In order to fulfill these responsibilities, my division maintains a staff of 56 employees, consisting of a manager, four supervisors, 16 accountants, 29 analysts and 6 clerks. Fourteen of the accountants have degrees in accounting or business administration, while many of the analysts have taken advanced accounting courses or have

worked previously in the operating departments.

Q. Have you been active in any professional organizations?

A. Yes. From 1974 to 1978 I was a member of the AGA-EEI Depreciation Accounting Committee and from 1978 to 1985 I was a member of the AGA-EEI Plant Accounting Committee. The Depreciation Accounting Committee is responsible for reviewing and studying new techniques in plant life analysis and the methods used to calculate book and tax depreciation. The Plant Accounting Committee is responsible for reviewing new and proposed regulations and legislation as they relate to plant in service and under construction, analyzing and making recommendations as to the proper implementation of the regulations or legislation, and reporting to member companies new and more efficient ways to account for and control plant in service costs. While a member of the Plant Accounting Committee, I was chairman of several subcommittees which dealt with construction overheads, third party billings, accounting for jointly owned projects and Plant Accounting Division interfaces with other departments and external organizations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the accounting procedures employed and the records maintained by the Plant Accounting Division which accurately record the cost of plant in service on the Company's books of account. I will explain why these records and procedures ensure that these

costs represent the original cost of plant in service supplying the needs of our customers.

Q. Please describe how the Company's Utility Plant records are maintained.

A. The plant records are maintained so as to conform with the Uniform System of Accounts for major electric utilities as mandated by the Federal Energy Regulatory Commission and the Pennsylvania Public Utility Commission. Plant in Service is the combined total of all costs included in Account 101 - Utility Plant Classified by Primary Account, and Account 106 - Completed Construction Not Classified. The cost of Construction Work in Progress is accounted for in Account 107.

The records maintained and the procedures followed in accounting for utility plant costs can be described best by following a project from inception to completion and its ultimate recording in the continuing property records. When a decision is made by the operating or engineering department to add or replace utility plant, management approval must be obtained prior to expending any funds or commencing work. At that time, it must be determined if the project is capital or maintenance. Once this is done, either a capital authorization or an expense authorization is prepared and circulated for the necessary approvals. Plant Accounting is part of the approval process and reviews all authorizations for proper accounting and, if it is a capital project, to ensure sufficient detail of costs

incurred will be provided to allow proper assignment of costs to the appropriate plant account. In the Uniform System of Accounts, these capital authorizations are referred to as work orders.

Once approved, work commences and the resulting costs are charged to the work order. During the construction phase, the costs charged to this work order and all other work orders under construction are reflected in Account 107. When the project is completed sufficiently to be ready for service or is physically placed in service, the operating department fills in the date on a form supplied to them by the Plant Accounting Division and forwards it to us. During that same month, the costs accumulated on the project are transferred from Account 107 to Account 106 and the accrual of Allowance for Funds Used During Construction ceases and the accrual of book and tax depreciation begins. All costs for the project are still maintained in a work order status since finishing costs and/or late charges may be incurred. Any retirement of plant costs which were physically replaced on this project are also recorded at this time. When all work has been completed and all costs have been charged to the project, the responsible operating or engineering department will close the project to the Plant Accounting Division.

A plant accountant in my Division is then assigned to unitize the work order which consists of assigning costs and quantities by location, primary account and to

the various continuing property record units (CPR) within each primary account. The accountant does this by reviewing engineering prints of the site where the work was done, physically inspecting the project, discussing the project with cognizant engineers or operating personnel, and reviewing written descriptions of the work performed by contractors or Company personnel. Once this analysis is completed, the quantities and costs for the work order are transferred from Account 106 and are included in Account 101. The costs and quantities are added to the continuing property records for that location in the detail described and the cost of retired plant are deleted.

Account 101 (costs and quantities) for that location therefore represents the original cost of utility plant in service, states what primary account the costs are assigned to (structures or equipment), and describes the property, the year installed and the applicable work order. This detail is necessary to allow for verification of costs to the physical plant and to provide for future retirements as they occur. Additionally, the use of a work order system and the procedure of notifying Plant Accounting when a project is placed in service or is ready for service, assures the timely recording of additions and retirements of utility plant in service. All of the records are automated and the work orders maintained in Accounts 106 and 107 plus the detailed continuing property record which comprises Account 101 are balanced each month to the

general ledger of the Company.

Q. Are the Company's Plant Accounting records audited?

A. Yes. The records are audited annually by an independent certified accounting firm and periodically by the Federal Energy Regulatory Commission, the Internal Revenue Service, the audit staff of the Pennsylvania Public Utility Commission and our own Internal Auditing staff. The audit staffs of each entity make random field examinations of plants to verify the recorded cost to the physical facilities during each audit.

The most recent Federal Energy Regulatory Commission (FERC) audit was completed in 1982 for the period 1979-1981. The FERC audits are general compliance audits and include an examination of utility plant accounts. They normally cover a three or five year period and all capital authorizations are reviewed. During that review, work orders are selected at random and checked thoroughly for adherence to FERC regulations and Company procedures. Areas of disagreement for the accounting of costs are usually resolved, but if necessary, correcting entries are made. The Pennsylvania Public Utility Commission staff participates in the exit conferences for these audits and receives copies of all correspondence. The final audit results transmitted to the Company state the value of the original cost of plant in service as recognized by FERC and that amount (as adjusted if necessary) is the recorded amount on the Company's books. More recently, the Division

of Audits of the Pennsylvania Public Utility Commission completed an audit of plant in service for the period 1979-1983. The results of this audit have not yet been received. Generally the results of the audits conducted by independent certified accounting firm, FERC, the Internal Revenue Service, the audit staff of Pennsylvania Public Utility Commission and our own Internal Auditing staff conclude that the Company records are accurate and in compliance with applicable regulations and procedures.

The IRS audits usually center on proper classification of costs by primary account and capital-maintenance decisions. Our Internal Auditing Division conducts periodic audits of all phases of Plant Accounting for compliance with regulatory requirements and adherence to Company procedures. The last audit was completed in 1982. Finally, the audits conducted by the Company's independent certified public accounting firm verify that the Plant Accounting records for utility plant do agree with the general ledger, random reviews of work orders for proper capital charges and accounting for costs of jointly owned projects.

Q. Do the amounts shown in the Utility Plant accounts accurately reflect the original cost of utility plant in service for the benefit of the Company's ratepayers?

A. Yes. In 1937, the Uniform System of Accounts was revised, requiring plant costs to be recorded at the original cost to the first user of that plant. A consulting firm was

employed to ascertain the original cost of plant in service and in the mid-1940's agreement on that amount was reached with the then Federal Power Commission and the Pennsylvania Public Utility Commission. The appropriate correcting entries were made to both plant in service costs and the accumulated provision for depreciation. Since that time, the work order system which I have previously described has been used to account for the additions and retirements of utility plant as prescribed by both commissions.

Q. Please describe what controls are in place within the Plant Accounting Division to assure that costs included in Plant in Service accurately reflect plant investment which is in service.

A. There are several such controls as described below:

1. Each month, an overrun and past due authorization report is sent to the responsible division citing work orders that have exceeded their authorized amounts by 10% and/or $10,000. An explanation of the overrun is required and in some instances uncovers improper charges which are then transferred to the proper account. If the costs are proper, the work order must be supplemented by requesting additional funding. Authorizations that remain open past their expected completion date are also included in this report and must be explained by the responsible division. The regular preparation of this report verifies that projects are still under construction and that the

Allowance for Funds Used During Construction is not being overstated.

2. Each day, a comparison is made of charges against the approved capital work order master file. Charges which were rejected because they had an invalid work order are investigated by Plant Accounting personnel. The work order number will be corrected to the proper number, or if it is found to be an improper capital charge, it is brought to the attention of the responsible department for proper accounting.

3. An ongoing dialogue is maintained with all responsible divisions charging to capital authorizations. I, or members of my supervisory staff and senior accountants, determine the proper accounting treatment for questionable costs about to be incurred.

4. Twenty-three analysts from Plant Accounting are located in seven service buildings located throughout the Company's service territory. These analysts work closely with our Transmission and Distribution (T&D) Department on a daily basis, advising the T&D accounting forces on proper capital/maintenance accounting for costs. They also verify that completed work orders receive only capital charges and that those charges reflect only the work performed and agree with the physical quantities recorded on the operating maps and records.

5. Our T&D Department uses an automated system to estimate

and track the quantities and cost of each electric distribution work order. This system uses average manhours to perform certain tasks and current labor and material costs to derive its estimate of cost for the project. If actual costs or hours deviate significantly from the estimate, a plant analyst from Plant Accounting will review the project with T&D personnel to determine the reason for the deviation. If it is found that maintenance type work was charged to the capital work order, those costs are transferred to the appropriate maintenance account.

6. The unitization process is the last but most extensive review of costs charged to the work order. In the process of assigning costs to each property unit, excess quantities of storeroom issues are investigated, invoices for purchased materials are reviewed, invoices for contract labor are checked for reasonableness, AFUDC charged to the project is verified and actual costs are compared to estimates for the project. All deviations are investigated and if found to be incorrect, the appropriate adjusting journal entry is made.

7. Physical inventories of plant, and comparisons of recorded quantities in the plant in service records to operating records are other controls that are used in my Division. Examples of plant where costs are verified in this manner are transformers, meters, spare power

transformers, tools and work equipment, and office machines.

Q. Are these controls exercised on large construction projects?

A. Not by the Plant Accounting Division. When large construction projects are undertaken by the Company, the General Contractor is given the responsibility of accounting for costs and quantities during construction and to provide a Final Cost Statement to Plant Accounting at the completion of the project.

At the beginning of the project, we in Plant Accounting will supply the level of detailed accounting categories required to the accounting staff of the General Contractor. Periodically, a Plant Accountant will review the accounting records to assure they are being kept accurately and in the level of detail required. The control of costs are the responsibility of the Divisions within the Company charged with overseeing construction of the project and these Divisions are assisted in this task by ongoing reviews of the project by our Internal Auditing Division.

Q. Please explain how the plant in service costs for Electric and Common Plant shown on pages B-3 through B-6 of Exhibit TPH-2 were developed.

A. The actual original cost of plant in service (combined total of Accounts 101 and 106) recorded on the books of the Company at June 30, 1985 was used as the base or starting point. These costs are reflected on pages B-3 through B-6

of Company Exhibit TPH-1.

The estimated cost of additions and retirements were extracted from the Company's Construction and Retirement budget for the period July, 1985 through June, 1986 and were added and subtracted respectively to the actual June, 1985 plant in service costs, to produce the estimated plant in service at June 30, 1986.

Q. Mr. Smith, do you believe that, based upon the accounting and internal/independent audit procedures which you have described above, that all investment shown in the Company's books of account as plant in service do reflect actual plant in service?

A. Yes, I do.

Q. Does this conclude your testimony?

A. Yes, it does.

ORIGINAL

PECO STATEMENT NO. 26

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION
VS
PHILADELPHIA ELECTRIC COMPANY
DOCKET NO. R-850152

DIRECT TESTIMONY
OF
JOHN B. COTTON

EXPLANATION OF THE LIMERICK GENERATING STATION ORGANIZATION FOR OPERATION AND MAINTENANCE

SEPTEMBER 1985

DOCKETED
SEP 27 1985

DIRECT TESTIMONY OF JOHN B. COTTON

Q. Please state your name and business address.

A. John B. Cotton, 2301 Market Street, Philadelphia, Pennsylvania 19101. My working location is the Limerick Generating Station.

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

A. I am employed as Plant Staff Maintenance Engineer in Philadelphia Electric Company's Electric Production Department at the Limerick Generating Station.

Q. What is your educational background and nuclear training?

A. I graduated from the U.S. Naval Academy in 1967 with a degree of Bachelor of Mechanical Engineering. I completed the U.S. Navy Officers' Nuclear Power Training School and the U.S. Navy Nuclear Power Prototype Training in 1968 resulting in qualification as Engineering Officer of the Watch for the S1W reactor. In 1969, I completed the U.S. Navy Submarine School, and was assigned to a nuclear-powered submarine in the

Engineering Department for three years, during which time I participated in both routine operations and an overhaul and reactor refueling. As a qualified Engineering Officer of the Watch, I served as Reactor Controls Officer, Electrical Officer and Machinery Division/Radiation Control Officer at various times during this period. Each position involved the direct supervision of reactor operation and related maintenance and, during the reactor refueling, involved special reactor and power plant testing.

In 1972, I joined Philadelphia Electric Company and continued to gain nuclear experience and training. In June, 1984, I received an NRC Senior Reactor Operator License for Limerick Unit 1.

Q. Please describe your work experience with Philadelphia Electric Company.

A. I joined Philadelphia Electric Company in 1972 as a Quality Assurance Engineer in the Quality Assurance Section of the Engineering and Research Department. In 1978, I transferred to the Electric Production Department at Limerick Generating Station where I am currently employed.

A detailed description of my principal activities in each of these positions is set forth in Appendix A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the permanent operating and maintenance organization employed by the Company at the Limerick Station, and the function and activities of that organization during normal plant operations. I will also describe the additional staffing, activities and resources which will be required during a normal refueling outage at Limerick. These descriptions will further support the Company's claims, as developed by Mr. John J. Carroll, for a normalized level of non-outage O&M and outage expenses setforth on pages D-10a and D-18 of Exhibit TPH-2.

Q. Please describe the organization that PECO has established to operate and maintain Limerick.

A. A chart summarizing the operation and maintenance organization for the Limerick Generating Station is attached to my testimony as Schedule 1. As this Schedule indicates, the Plant Manager heads the organization and has responsibility for the

safe and economic operation of the Limerick facility. Reporting directly to the Plant Manager are two Superintendents with functional responsibility for the plant's Operations and Services, respectively. I should note that the NRC requires that either the Plant Manager or one of the Superintendents be qualified as a Senior Reactor Operator and, in fact, the Superintendent - Operations has received such a license. The Superintendents, in turn, share responsibility for the following six functional areas of station operations: Operations, Technical Engineering, Chemistry, Maintenance, Health Physics and Outage Planning. In addition, there are three functional areas which report directly to the Plant Manager. These include Administration, Regulatory Engineering and Emergency Preparedness. The heads of each functional area of the Limerick organization along with the Plant Manager and Superintendents comprise the Senior Plant Staff.

In total, there are approximately 900 personnel who are currently assigned to staff Limerick on a full-time basis during normal operations, and the equivalent of 60 full-time personnel who provide

routine operations and maintenance support from the Company's headquarters in Philadelphia. During a typical refueling outage, the additional manpower required at Limerick will exceed 300 people. The permanent Limerick staff and any other support personnel physically working at the plant site are directly supervised and managed by the Plant Manager and his organization. Personnel providing support away from the plant are administratively managed by their respective organizations but are coordinated by and provide support services at the direction of the Plant Manager and his staff.

Q. Mr. Cotton, would you please describe the organization and functions of the Operations Group.

A. The Operations Group is headed by a graduate Engineer who holds a Senior Reactor Operator License, as required by the NRC. Reporting to this individual are the the Shift Technical Advisors, a specially trained group of graduate Engineers, required by the NRC for each shift, and the entire Shift Operating staff which consists of 12 post positions staffed on a 24-hour per day basis. Six operators are required

for each post position in order to cover the 21 shifts per week, provide for requalification and support training, meet the requirements for vacation and leave time, and adhere to the NRC's overtime limitations. In addition, a staff of Engineers and Technical personnel, the Chief Electrician and Rad Waste Supervisor also report to the head of the Operations Group.

The specific functions of this group are to conduct the minute by minute operations of the plant. The shift operating staff is headed by a Shift Superintendent, who has overall responsibility for the plant during his shift. In addition to this individual, the normal operating shift for Limerick consists of 2 Shift Supervisors, 1 Control Room Operator, 1 Reactor Operator, 3 Plant Operators, 1 Assistant Plant Operator, 2 Auxiliary Operators, and 1 Helper. In addition, each shift complement has 2 maintenance craftsmen, 2 Instrument Technicians, 1 Health Physics Technician, 1 Chemistry Technician and 1 Clerk. This size staff is necessary to manage and operate the reactor, electrical, and auxiliary systems in a safe manner, to accomplish the necessary routine

testing which is a shift responsibility, and to provide an on-shift capability to respond to off-normal or emergency situations. Moreover, the above staffing levels meet the requirements established by the NRC and normal power plant operating practices.

Six shifts of each operating crew are used at Limerick to permit one operating crew to be in training at the Limerick Training Center. An ongoing training program for licensed operators is not only an NRC requirement, but is also a prudent method to assure that necessary skills are maintained at the proper level, that plant modifications are described to and understood by the operators, and to ensure that significant lessons learned throughout the industry are passed on to our personnel in a professional and educational manner.

I should note that NRC regulations require that one Shift Supervisor be present in the Control Room at all times. A second Shift Supervisor is therefore assigned to supervise and monitor operations for the Nuclear Steam Supply System (NSSS) and the balance of plant outside the Control Room. Typically, this second Supervisor,

and 7 operators under his direction, are responsible for inspecting all plant equipment, performing those functions necessary to comply with NRC operating regulations such as surveillance testing, and conducting other activities required for the operation of any generating station, such as lubrication, blocking, permit clearing, etc.

Q. Mr. Cotton, would you please describe the organization and functions of the Technical Engineering Group.

A. The Technical Engineering Group is headed by a graduate Engineer who, like the head of Operations, is required by the NRC to be qualified as a Senior Reactor Operator. The group consists of approximately 185 personnel and is made up of Engineers, Technical Assistants and Technicians. Their overall responsibility is to provide the general technical support required to manage and operate the station in a safe and efficient manner and meet the NRC requirements for testing and reporting. This group provides the technical analysis required by the station's Plant Operations Review Committee (PORC) and Nuclear Review Board (NRB) with respect to

modifications, abnormal conditions and transients. They also prepare responses to NRC communications, prepare test procedures, perform tests required for plant modifications and cooperate with the Institute of Nuclear Power Operation (INPO) in its review of industry problems.

The Technical Engineering Group is divided into five subgroups: Reactor Engineering, Instrument and Control, Performance, Projects and Computer Support. The Reactor Engineering Group, which is comprised primarily of Nuclear Engineers, is responsible for providing technical support for reactor operations, including reactor core performance monitoring as required by the NRC and for fuel economy, for sequencing of control rod manipulation and for the operation of certain systems closely associated with the reactor. Instrument and Control, which is the largest group within Technical Engineering, is responsible for performing the extensive surveillance testing required at Limerick and for maintaining, calibrating and troubleshooting the instrument and control portions of all plant systems. The Performance Group is comprised of

Engineers and Technical Assistants and has responsibility for monitoring plant and equipment performance, providing technical input for the station preventive maintenance program, reviewing operating and system procedures and coordinating all surveillance tests. The Projects Group performs special analyses and projects designed to improve plant operations and reliability, which may result in changes to operating procedures and/or plant modifications. Finally, the Computer Group performs maintenance and troubleshooting functions for the plant's numerous computers, and provides assistance in the development and modification of computer software.

Q. Please describe the staffing organization and major activities of the Chemistry Group.

A. The Chemistry Group is headed by a Senior Chemist who has a Ph.D in Chemical Engineering. This group consists of approximately 28 personnel, including Chemists, Technical Assistants and Technicians. It is responsible for performing a variety of analyses to ensure compliance with Company standards and practices reflective of prior operating experience, NRC Technical

Specifications, equipment manufacturers' recommended standards and environmental requirements imposed by the Environmental Protection Agency (EPA) and the Pennsylvania Department of Environmental Resources (DER). Specific activities of this group include the routine sampling and analysis of plant operating fluids such as reactor coolant, condensate, hydraulic fluids and lubricating oils. This group is also responsible for analyzing plant effluents and air samples. Using these analyses, this group develops and examines trend data and recommends corrective actions when their analyses indicate trend deviations or that regulatory limits may be exceeded. Although most of the work of this group is performed at the plant, it receives consulting and special test support from the Chemistry Laboratory located in the Company's Philadelphia Office.

Q. Mr. Cotton, would you please now describe the Maintenance Group organization and its activities.

A. The Maintenance Group, over which I have direct responsibility, consists of approximately 20 Engineers and Technical Assistants. The

responsibilities of my Group include troubleshooting equipment problems, defining plant conditions under which authorized repairs are to be performed, ensuring spare parts availability, writing and approving maintenance procedures and ensuring that proper plant and work conditions are established in a timely manner throughout the plant. This group also implements the Preventive Maintenance and Environmental Qualification Maintenance Programs, analyzes equipment failures, and performs designated surveillance tests. These activities are required to provide for safe operating conditions and plant performance, to promote plant availability and reliability, and to meet specific NRC and environmental requirements related to maintenance.

Another responsibility of my group is to coordinate the activities of certain on-site support groups. For example, we establish the priorities and schedules for work performed at Limerick by the Company's Maintenance Division which has a permanent staff of approximately 150 supervisors, technical personnel, and craftsmen. I am directly responsible to the Plant Manager

for the successful completion of Maintenance Division work and for the coordination of their activities with other station groups. I am also responsible for coordinating Stores Division activities (10 people) at the Limerick Storeroom. Under the Radwaste Services Contract, for which my group has administrative responsibility, approximately 50 personnel perform routine power block cleanliness and decontamination activities. In addition, approximately 35 personnel provide non-power block janitorial services as directed by the Company's Building Management representative who reports to me for coordination. The Plant Housekeeping Coordinator, who is also under my direction, establishes cleanliness standards and monitors the plant for compliance with these standards. Finally, the Nuclear Plant Reliability Data System, an INPO computer network for reporting equipment problems, is operated by my group.

Q. Mr. Cotton, please describe the organization and activities of the Limerick Health Physics Group.

A. This group is headed by a Senior Health Physicist, who holds a Masters Degree in Nuclear Engineering and is a certified Power Reactor

Health Physicist as required by specific NRC requirements for this position. This Health Physics Group consists of approximately 66 Physicists, Technical Assistants and Technicians, and is further broken down into two subgroups - Applied and Support Health Physics. The Applied Health Physics Group provides onshift Health Physics personnel who are responsible for conducting routine radiation and contamination surveys throughout the plant, implementing procedures which ensure that proper protective clothing and radiation monitoring devices are worn by all personnel, and performing daily on-the-job radiation and contamination monitoring activities to ensure personnel safety.

The Support Health Physics Group provides personnel dosimetry and radiation monitoring devices, establishes special dosimetry requirements to meet specific job monitoring conditions, monitors procedures and records for radwaste shipment and transportation, and supervises the issuance, recovery and cleaning of all radiological protective clothing and respiratory protection equipment. Support Health Physics also serves the important function of

reviewing work plans and procedures to minimize personnel radiation exposure pursuant to Company policy and NRC ALARA requirements.

Q. Please describe the Outage Planning Organization and its functions.

A. The Outage Planning Group is headed by a graduate Engineer who has extensive experience in plant maintenance and has been trained in Limerick Station operation as evidenced by his certification on the plant simulator. This group has a non-outage staffing level of 14 Engineers and Technicians. The primary responsibilities of this group are to schedule and coordinate outage activities in order to minimize work conflicts and reduce the down time of the station, monitor maintenance activities and the various industry problem and improvement reports to identify outage related work activities, and plan jobs which will be required during upcoming outages. Work sequences, particularly for fuel floor, under-reactor vessel, in-reactor vessel, and in-containment activities, are developed by this group to ensure that work group activities do not conflict or cause overcrowding in limited-access areas. Outage work sequences are also reviewed

by Health Physics to achieve the Company's goal of maintaining personnel radiation exposures as low as reasonably achievable (ALARA).

Prior to starting an outage, representatives from certain vendors (such as the main turbine and the reactor suppliers) are expected to be added to the outage planning staff. They will make final reviews and adjustments to work plans and procedures and, during the outage, will be available for technical support. The Outage Planning staff will also be augmented with schedulers and technicians to monitor and report work progress, coordinate the activities of plant groups such as Health Physics, Quality Control and Maintenance, and to update schedules and manpower requirements. Approximately 15 additional personnel may be added to the Outage Planning Staff just prior to and during an outage. In addition, Maintenance Division personnel at Limerick is expected to reach 400 with an additional 40 Health Physics technicians required to support increased outage work activities.

A number of other personnel increases will also be necessary to support Limerick outage

activities: Fire Watch personnel to monitor increased welding activities; Security Force members to assure adequate security coverage; Storeroom personnel to handle parts and materials; Quality Control personnel to perform the increased inspection activities; Technical Staff personnel to determine post-work testing requirements and perform various outage tests; and Radwaste Contract personnel to perform decontamination and cleanup activities and to construct work containment structures.

During an outage, the Maintenance Group coordinates with the Outage Planning Group to ensure that work is accomplished in the proper priority and also provides assistance in the areas of technical reviews, spare parts availability, plant staff coordination, and procedural controls.

The Modifications Engineer, a key member of the Outage Planning Group, is a licensed Senior Reactor Operator who is responsible for the plant modification proposal, review and approval process at Limerick. He coordinates with our Engineering and Research Department and various plant staff groups to assure that proper

technical reviews take place, that design and installation packages are prepared, that modifications are scheduled, and that Modification Acceptance Tests are performed. His group also assures that all procedures, drawings, plans, spare parts lists etc. are revised to reflect the "as-modified" plant and are ready for use when the modification is completed. The group also prepares a Modification Training Package, when appropriate, to inform plant operators and licensed staff members of modifications and their effect on plant operations.

Q. Mr. Cotton, would you please describe the staffing and activities of the Administrative Group.

A. The Administrative Group consists of over 250 personnel with diverse responsibilities. It is headed by a Senior Staff Engineer who is responsible for coordinating the activities of three sub-groups, as well as the activities of three Divisions within the Company in their support of Limerick Station operations.

The Sub-groups at Limerick Station include:

- Secretarial and Clerical Support. This group consists of approximately 40 people who provide secretarial and clerical support for the entire Limerick Station operating Organization.

- Security. This group consists of 6 PECO employees who coordinate the activities of an approved nuclear contract guard force of approximately 200 people. Its primary responsibility is to control and monitor access to the designated protected area at the station and certain vital areas within the power plant, as specified by NRC security requirements for nuclear facilities.

- Cost Analysis. This group is responsible for budget and cost control activities, and consists of a degreed employee supported by the clerical staff.

As noted, the Administrative Group is also responsible for coordinating the Limerick support activities of three Company Divisions. The first is the Safety Division within the Company's

Personnel and Industrial Relations Department which is responsible for establishing industrial safety procedures and conducting industrial safety inspections. The Records Management Section of the Systems Division, within the Company's Finance & Accounting Department, is coordinated through the Administrative Group and provides approximately 25 people who maintain station records in conformance with NRC requirements. The third is the Training Section of the Electric Production Department which, through the efforts of approximately 30 people, provides the NRC qualification and requalification training and the Company's progression and continuing training for personnel at the Limerick Station. The Training Program for Limerick Station is presently in the process of being accredited by INPO as a qualified training program and meets all appropriate NRC requirements. I should note that the Limerick Training Program, because it requires the expenditure of substantial time by Station personnel, contributes significantly to the level of operating expenses incurred.

Q. Mr. Cotton, would you please describe the Regulatory Engineering and Emergency Preparedness Groups.

A. The Regulatory Engineering Group is headed by the Regulatory Engineer and is supported by an Engineer and a Fire Projection Assistant. The Regulatory Engineer is responsible for coordinating and managing the entrance and exit meetings between station management and the NRC, INPO and the Company's QA/QC organizations. He is responsible for reviewing and implementing new or revised quality requirements, investigating and developing Licensee Event Reports submitted by station management to the NRC, and reviewing and tracking the results of inspection and audit reports. In addition, the Fire Protection Assistant is responsible for monitoring plant activities for fire hazards and assuring compliance with the plant's fire protection program, and is generally available to assist all station groups in fire protection matters.

The Emergency Preparedness Group consists of a single coordinator who is under the direct supervision of the Director for Emergency Preparedness in the Company's Electric Production

Department. This individual is responsible for working with plant staff to implement on-site emergency procedures and acts as liaison with outside entities regarding on-site emergency procedures and activities.

Q. Mr. Cotton, in addition to the groups described above, are there any other areas of the Company that support Limerick operations?

A. Yes, within the Electric Production Department, additional support is supplied to Limerick by Nuclear Production in the area of Nuclear Fuel Management, Nuclear Licensing, Independent Safety Engineering Analysis, Emergency Planning, Quality Assurance and Quality Control. Also, support is received from the Services Division for cost control and expertise with respect to Company and industry experience on historical performance and costs associated with nuclear plants. This support for Limerick Station is equivalent to approximately 60 additional full-time personnel. Support is also received from the Engineering and Research Department on an as-needed basis for jobs that require their specific expertise.

Q. What management controls have been established to ensure the efficient and effective operation of Limerick?

A. Throughout the fuel loading and testing phases at Limerick, we have made extensive use of schedules to plan the most efficient way to achieve commercial operation. Resoures are assigned to support the schedules and progress is closely monitored by all Senior Staff members. Each weekday, the Shift Superintendent holds a meeting which is normally attended by the Plant Manager, Superintendent - Operations, and Senior Staff members or their representatives. The purpose of this meeting is to review plant activities for the previous shifts, to identify problems needing attention, and to cover the plan of operation and maintenance for the day. In addition, a daily "TRI-POD" meeting (3-day look ahead) is held. This meeting is chaired by a Senior Plant Staff member and is attended by representatives from all plant staff groups and from all support groups. Overall plant and systems status and operational plans are reviewed and each group reports on the status and plans for their work over the next three day period. This meeting

assures that all groups are aware of plant goals and can support them, helps to identify and resolve potential work group conflicts, and allows some tasks to be combined in a manner which reduces operator blocking efforts and minimizes the amount of equipment removed from service. This meeting also serves as a vehicle to rapidly distribute information to the staff regarding changing radiological conditions in the plant, industrial safety matters and other matters of general interest. These specific controls, plus routine staff and PORC meetings, will continue to be used to manage and control normal plant operations and will be supplemented when needed.

Q. Have the Company's organizations and activities for Limerick Generating Station been reviewed by the NRC or other independent third parties?

A. Yes. An important part of our pre-operational license activities at Limerick was a thorough review of the plant organization by the NRC and the Advisory Committee on Reactor Safeguards, which found them to be acceptable as evidenced by the granting of an Operating License.

Q. Does this conclude your testimony?

A. Yes, it does.

Appendix A

Philadelphia Electric Company Work Experience of John B. Cotton

I joined Philadelphia Electric Company in 1972 and was assigned to the Quality Assurance Section of the Engineering and Research Department. While in this position, I reviewed component and equipment specifications for Quality Assurance and Quality Control provisions, reviewed component vendor Quality Assurance Manuals, performed Quality Assurance audits, and witnessed certain inspections and tests at vendor sites for the facilities at Limerick Generating Station. During this period, I also completed a 12-session course of the 1974 ASME Boiler and Pressure Vessel Code, Section III presented by the ASME-Engineers Club and completed the Drexel University Professional Engineering Registration Examination Review course.

In 1978, I was transferred to the Electric Production Department at Limerick. I was responsible for the operation and maintenance of the auxiliary boilers, plant heating system and water treatment facility, for review of various sections of the Final Safety Analysis Report for operational and

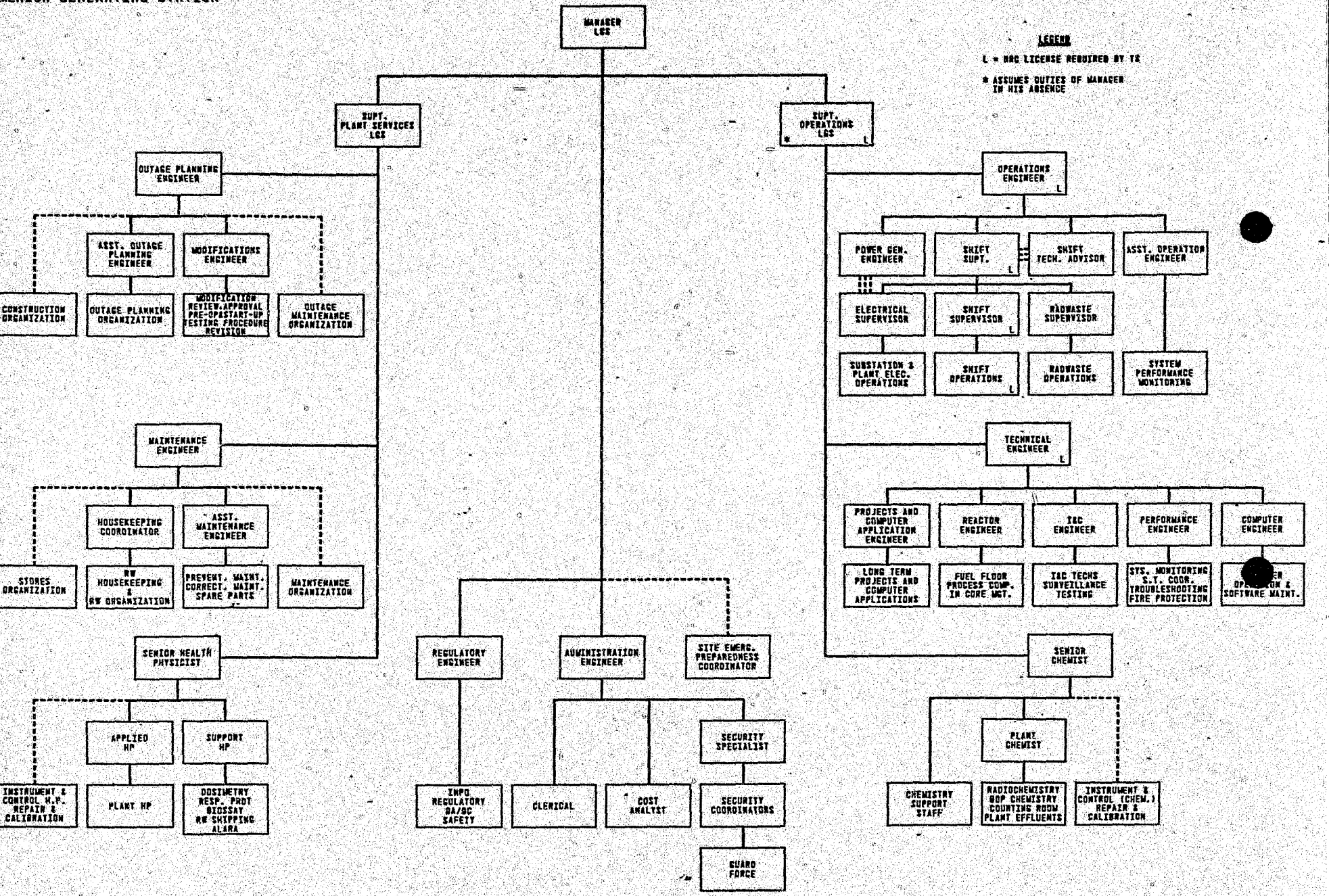
maintenance considerations, and for preparation of sections of the Final Safety Analysis Report assigned to me, including the Emergency Plan. I also participated in the overall planning for the organization and staffing of the Limerick plant. In 1980, I completed a Radiological Emergency Response Coordinators course presented by the NRC and a two-week Research Reactor Training course at Pennsylvania State University.

In 1981, I was assigned as Plant Staff Maintenance Engineer at Limerick. I was responsible for development of the maintenance organization and maintenance program, including the programmatic controls under which maintenance is performed, preparation and approval of detailed maintenance procedures for plant equipment, preparation of the preventive maintenance program, and installation of a computer system used to assist in the maintenance document process and to maintain equipment histories. I am responsible for defining maintenance tasks, both corrective and preventive, to be performed by the Maintenance Division, for setting maintenance priorities and schedules, for coordinating with the operations staff to make equipment available for maintenance and with the Health Physics and Quality

Control staffs, for implementation of the environmental qualification maintenance program, and for failure and trend analyses. I serve on the Plant Operations Review Committee (PORC), which is a senior staff organization responsible for reviewing a wide range of technical and administrative matters and for making recommendations to the Plant Manager on nuclear safety topics. In 1981, I completed the twelve-week Boiling Water Reactor Simulator Senior Operator Certification Course and a one week Process Instrumentation and Controls Course.

Schedule 1

MERICK GENERATING STATION



ORIGINAL

PECO STATEMENT NO. 27

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v. PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

DIRECT TESTIMONY OF
N. BARRIE McLEOD, Ph.D., P.E.
E.R. JOHNSON ASSOCIATES, INC.

NUCLEAR PLANT DECOMMISSIONING COSTS

September 27, 1985

DOCKETED
SEP 27 1985

DIRECT TESTIMONY OF N. BARRIE McLEOD, Ph.D., P.E.

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

A. My name is N. Barrie McLeod. My business address is 11702 Bowman Green Drive, Reston, VA 22090.

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

A. I am currently Vice President of E. R. Johnson Associates, Inc. (JAI), a consulting firm specializing in the technology and costs of nuclear facility design, operation, decommissioning and waste disposal. However, the development of nuclear decommissioning cost estimates for Philadelphia Electric Company, which is the subject of my testimony, was performed within NUS Corporation under my direction as Vice President of Major Projects at NUS, a position I held until October 1984. I continue to work for NUS as an independent consultant and for the purposes of this testimony I am representing NUS Corporation and sponsoring the work done by that organization under my direction and supervision.

Q. Please describe NUS Corporation and its activities.

A. NUS Corporation is a specialized consulting engineering service company with headquarters located in Gaithersburg, Maryland and with offices in eleven other cities in the United States and in five foreign countries. The total staff

is over 1400 people. NUS' major services are in the area of nuclear and fossil-fueled power generation and fuel supply, environmental engineering and industrial waste treatment and process design. NUS provides these services to utility, industrial and government clients, both domestic and foreign.

Q. What is your educational background?

A. I obtained my Ph.D. degree in Nuclear Engineering from the Massachusetts Institute of Technology. I also have a bachelor's degree in Engineering Physics and a master's degree in Nuclear Engineering.

Q. Please describe your work experience.

A. I have over 25 years of experience in Nuclear Engineering and am a Registered Professional Engineer. My earlier responsibilities were for all NUS client work in the field of nuclear fuel management including both technical and cost aspects of nuclear fuel supply. My responsibilities were later expanded to cover the financial evaluation of competitive bids for commercial nuclear power plants. In addition, I have had supervisory responsibility for nuclear plant safety analyses, licensing, pre-operational testing and start-up. My more recent responsibilities include nuclear power plant costs, decommissioning costs, nuclear fuel supply and nuclear waste disposal as a part of the Energy Systems

and Major Projects activities at NUS. Since joining JAI, I have been working principally in the planning and conceptual design of major nuclear waste disposal facilities and in developing the related costs of construction, operation and decommissioning.

Q. Please describe your experience in estimating the costs of nuclear plant decommissioning.

A. Through 25 years of work in the field of nuclear power plant and fuel engineering, I have obtained an in-depth knowledge of nuclear power plants and their systems, licensing, construction, start-up, operations, waste management and decommissioning, plus the supply, use, storage and disposal of their fuel. My direct experience with decommissioning costs began shortly after the publication of SEC Staff Accounting Bulletin No. 19 in early 1978, which was the first official recognition of the need to collect current revenues for the ultimate decommissioning of nuclear power plants. Initially, I developed a method of decommissioning cost recovery which explicitly accommodates inflation as it occurs and also provides equitable treatment of ratepayers over time. I subsequently have directed the development of decommissioning cost estimates for 6 nuclear units owned by 4 utilities and have participated in others. I have served as an expert witness on decommissioning and spent nuclear fuel

cost recovery in rate hearings before the Florida Public Service Commission, the Federal Energy Regulatory Commission and the Pennsylvania Public Utility Commission. In the latter case, I have served as the Company's expert witness in these areas before this Commission at Docket Nos. R-79060865, R-80061225, R-811626, R-822291. I also have presented several papers at professional society meetings and industry conferences on decommissioning costs and cost recovery.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the development and support for the total and nuclear portions of the estimated costs for decommissioning Philadelphia Electric Company's Peach Bottom, Salem and Limerick 1 nuclear power plants. I will provide these cost estimates as base costs in March 1984 dollars and will also provide a breakdown of these costs to be employed as the basis for escalating these base cost dollars to current and projected future dollar levels. The nuclear portions of the decommissioning costs developed in this testimony are the basis for the Company's request for current revenues to pay for future decommissioning as described in the testimony of Mr. Richard Wright.

A detailed description of nuclear plant decommissioning and the development of the specific decommissioning cost estimates for the Company's nuclear plants are set forth in

Exhibit NBM-1, "Decommissioning Cost Estimates for Limerick Generating Station Units 1 and 2, Peach Bottom Atomic Power Station Units 2 and 3, and Salem Nuclear Generating Station Units 1 and 2." Exhibit NBM-1 itself is a summary of separately bound studies of the cost of decommissioning each station. These supporting volumes set forth the detailed calculations and allocations supporting the cost estimates developed in Exhibit NBM-1. Copies of these supporting documents will be provided upon request.

Q. Please describe what is meant by the decommissioning of a nuclear power plant.

A. When a nuclear power plant reaches the end of its operating life, it must be placed in a condition such that public health and safety is ensured against exposure to residual radioactivity or other hazards present in the facility at the time of shutdown. The various activities and processes required to achieve such a condition are collectively referred to as "decommissioning" of the nuclear power plant. There are three possible overall approaches to decommissioning:

1. Prompt Removal in which all radioactive materials above safe limits are removed as soon as practicable after shutdown and are packaged and shipped to a licensed burial site for disposal. The remainder of the facilities are removed via conventional demolition.

2. Delayed Removal which is similar to prompt removal except for an interim delay period during which much of the original radioactivity decays. Although there is some reduction in the amount of radioactive material disposal, significant monitoring and security costs are incurred during the interim delay period.

3. Entombment in which the radioactive portions of the facility are entombed by the use of welded plates and/or poured concrete to physically assure isolation of those parts of the facility.

The Nuclear Regulatory Commission (NRC), which has licensing jurisdiction over a nuclear plant until all radioactivity is removed, has indicated that it will not accept Entombment for large power reactors. Prompt Decommissioning is the NRC's preferred approach and Delayed Decommissioning of up to 30 or 50 years would be acceptable if significant benefits could be demonstrated.

The decommissioning cost estimates described in this testimony are based on prompt decommissioning of the Company's nuclear units. Prompt decommissioning was selected because it is somewhat less expensive than delayed decommissioning, and because it reduces the financial risks that could arise from changes in regulations or from maintaining the purchasing power of accumulated funds over

longer periods. The costs of delayed decommissioning include costs for initially securing the facility against intrusion and continuing costs of security, monitoring and insurance over the dormant period. These added costs are greater than the reduction in the ultimate costs of removal and disposal that would be realized because of radioactivity decay to lower levels.

It should be noted that although some spent fuel will still be present on site at the end of the operation and will have to be removed prior to completion of decommissioning, the cost of such removal is not included as a part of decommissioning cost because it has already been included as a part of fuel cost during the operation of the power plant.

Q. Please summarize the processes that will be used to decommission the Company's nuclear units following their final shutdown.

A. The sequence and nature of decommissioning activities are largely determined by their most important goal: the safe removal and permanent disposal of all radioactive materials and equipment that remain from plant operations. The specific activities and sequences are selected on the basis of their being the most safe and effective way of physically removing and transferring all radioactive materials and equipment into appropriate licensed sealed containers;

shipping these containers, in shielded casks when necessary, via licensed transport over approved routes to the disposal site; and disposing of these packages at the licensed and regulated permanent disposal sites by underground burial. The remainder of the structures and equipment are removed and disposed of using conventional salvage and demolition practices and the site is then restored to original grade or its usable equivalent.

The principal strategy for ensuring the control of radioactivity during decommissioning is to initially maintain the integrity of the plant's containment structures which control radioactivity during operation and to maintain the operability of the plant's radioactive waste processing systems. In this way, the removal of much of the plant's radioactive materials and equipment is conducted within systems designed to control radioactivity, and is supported by existing systems for processing, compacting and packaging radioactive wastes. Once the other radioactive portions of the plant are removed and packaged, the containment and radwaste systems are themselves decontaminated, dismantled and packaged, completing the removal of all radioactive materials.

The actual decommissioning program activities which accomplish the above general goals can be broadly categorized

into four areas: 1) pre-shutdown planning and preparation; 2) decontamination; 3) equipment removal; and 4) site restoration. These activities proceed generally in the sequence as listed, but there is some overlap between the decontamination and equipment removal. Additional detail on these activities is as follows:

1) Pre-Shutdown Activities

The physical decommissioning of a large nuclear unit is a complex project extending over many years. Thus, sound decommissioning project planning is essential for ensuring that decommissioning activities will be carried out in a safe, timely and cost-effective manner. The NRC specifically requires that a decommissioning plan be submitted no less than one year prior to operating license expiration. This plan will be the basis for amending the NRC facility license from an operating license to a license which permits possession of radioactive materials until they are removed from the site. The planning and related preparations need to be started about three years prior to shutdown and include:

- Preparation of the detailed decommissioning plan for overall project control and scheduling purposes and to meet NRC licensing requirements.
- Preparation of task work plans, staffing plans, and development of procedures.

- Preparation of a quality assurance plan that assures implementation of safety-related procedures and the documentation thereof.
- Selecting special technologies and procuring, designing and testing special equipment.
- Establishing procedures and equipment to ensure occupational and public safety during decommissioning and a radiation survey plan for final release of the site.
- Training project staff and establishing training plans for contractor labor.
- Selecting prime and specialty contractors and subcontractors.
- Selecting the site and transport routes for radioactive waste disposal.
- Selecting the site(s) for non-radioactive waste disposal.

2) Decontamination

At the time of final shutdown, there will be significant radioactive contamination on the surfaces of process systems, equipment and some structures. The goal of decontamination is to promptly remove the bulk of this radioactivity to minimize subsequent personnel exposure and to clean as much material as possible to unrestricted levels, maximizing salvage, and minimizing packaging and disposal. The basic

strategy is to quickly remove as much of this contamination as possible with the simplest methods available and then to use increasingly aggressive and difficult methods.

The simplest methods involve chemical and electro chemical dissolution of the surface films and physical cleaning using vacuuming and scrubbing supplemented by detergents and cleaning compounds. The resultant radioactive liquids and solids are processed and packaged through the plant's existing liquid and solid radwaste facilities. Components whose metal surfaces remain contaminated after this cleaning must be disposed of using the equipment removal techniques described in the next section. Concrete surfaces which remain contaminated can be physically removed (such as by scabbling) and the resulting rubble packaged for radioactive waste disposal. At the completion of the decontamination phase, the majority of the plant radioactivity will have been removed and the principal remaining sources of radioactivity will be in contaminated equipment and systems.

3) Equipment Removal

Once the majority of removable radioactivity has been packaged and shipped for permanent disposal, and the working level of radiation has been correspondingly reduced to the maximum extent, the removal of major equipment and systems can proceed. During this phase, all radioactive equipment is

cut into pieces small enough for disposal packaging and all non-radioactive equipment is removed and salavaged as either scrap or used equipment. The actual sequence of removal is dependent upon the accessability of particular components and the potential personnel exposures. In general, the most radioactive components are removed first or shielded until they can be removed. Systems and components are cut into packagable sections using plasma-arc torches, arc saws, oxyacetylene torches or power saws. Small contaminated equipment is removed and packaged in standard containers. Piping is cut to fit standard packages and tanks are cut into plate segments for packaging. Reactor vessel internals are removed from the vessel, cut up and packaged. The reactor vessel is cut up into segments using a remote manipulator and is packaged. Certain vessels which are only mildly contaminated, such as steam generators, may be removed whole, their openings welded shut, and shipped for direct disposal. Previously-inaccessible contamination is then removed and packaged. All packages are loaded to be within licensed limits, some are shipped unshielded and others are shipped in shielded casks, depending upon approved transport requirements. Once all radioactive materials have been removed, and all areas of the site are verified to meet the standards for unrestricted use, the NRC license can be terminated. Non-contaminated equipment is removed and taken off-site for salvage as scrap or as used equipment.

4) Site Restoration

Once all radioactive materials have been removed, packaged and shipped off-site for permanent disposal, and all other salvageable equipment has been removed, the site is restored to original or equivalent usable condition by the following:

- o Demolition of all remaining structures to at least three feet below grade.
- o Removal of cooling water intake and discharge structures.
- o Collapsing or filling subterranean voids more than three feet below grade, including collapsing of conduits to the turbine building.
- o Disposal of all demolition material and rubble at an approved nearby landfill.
- o Grading, backfilling, replacement of soil and planting, as required to restore the site to original or equivalent.

Q. Please describe how the demommissioning cost estimates were developed for the Company's three nuclear sites.

A. First, the basic criteria and key assumptions were established. Consistent with these, each nuclear unit was systematically catalogued as to specific quantities of the many different items requiring removal and disposal or salvage. Then, the cost of removing and disposing of one

unit of each of the many items was determined. In this way the total direct costs of removing and disposing of all of the items in each unit were obtained. From these, the total cost of decommissioning was developed by adding the prime contractor's costs, the utility's planning and supervisory costs, and the costs of several specialty contracts. This process is summarized in greater detail, as follows:

Basic Criteria:

1. Decommissioning would be accomplished using current proven technology, under current regulations and radioactive waste would be disposed of at currently available disposal sites. Should the technology, regulations or disposal location change in the future, proper adjustments would be made at that time.
2. The integrity of radioactivity containment and isolation structures would be maintained until radioactivity removal was substantially complete in order to prevent release of radiation into the environment.
3. Decommissioning would be performed by a prime contractor with technical and management oversight by the Company. Certain specialized subcontracts would be awarded for decontamination, waste solidification, conventional demolition, and for health physics and security services.

Key Assumptions

1. Decommissioning will begin immediately following removal of all spent fuel from the site.
2. All radioactive systems and surfaces will be decontaminated prior to dismantling.
3. All large radioactive components will be cut up as necessary to facilitate packaging, transport and disposal.
4. All radioactive waste will be disposed of at the closest licensed disposal facility which is located in Barnwell, South Carolina.
5. Major structural demolition would not begin until after removal of all radioactive materials from the facility.
6. Non-radioactive debris would be disposed of at an on-site landfill at Peach Bottom and Limerick and by sealed disposal at a site 50 miles from Salem.
7. Each site would be restored to a graded and landscaped natural condition.

Cost Development

Initial cost development began with site visits to directly view station layout and obvious features that could impact decommissioning, and to establish the availability of necessary information. An extensive review of the information provided by the Company was then conducted.

Mechanical and electrical engineers used station equipment lists, general arrangements drawings, piping and instrument drawings and licensing documents to identify and quantify components and quantities. Civil engineers reviewed station layout, yard, structural steel and concrete drawings to identify buildings and structures, to classify types of construction and to quantify materials requiring decommissioning. The specific steps in the cost estimating process are as follows:

1. A data base was established for each nuclear station, listing all equipment, structures, materials and services required in decommissioning.
2. The specific quantity of each item on the list was determined. The units used (yd^3, linear feet, tons, etc.) were appropriate to the item and were consistent with the unit costs for that item.
3. Each item was also characterized as belonging to a particular class of unit cost for removal, for disposal, and for salvage.
4. The actual cost for removal of one unit of each class was developed considering fully burdened labor costs, the mix of skills required and the labor productivity losses due to the particular nuclear environment in which the category of work must occur. Demolition engineers provided basic estimates of labor productivity

for various activities. Similar unit costs were developed within each class for the cost of disposal and credit from salvage.

5. Each item in the data base was also identified as to which unit (or common portion) it belonged within the station, the FERC account to which it belonged, and also whether it was a part of the nuclear portion of the plant or not.

6. The quantities of each item in the data base, when multiplied by the unit cost for the designated category of removal, disposal and salvage cost, yield the total removal and disposal costs and the salvage credit, and the overall total for each item in the data base. The grand total for all items in the data base gives the total decommissioning cost for the station; and the grand total of all nuclear-related items in the data base gives the total nuclear-related decommissioning cost for the station.

Q. Please describe the total decommissioning costs that were obtained and discuss the principal reasons for the differences among the stations.

A. The following table summarizes the total cost of decommissioning the Company's Peach Bottom and Salem stations and Unit 1 of the Limerick station:

Total Decommissioning Cost
in March 1984 Dollars
($ Millions)

Station	Removal	Disposal	Salvage	Total
Peach Bottom 2&3	235.1	65.3	(7.9)	292.6
Salem 1&2	171.8	46.3	(6.5)	211.6
Limerick 1 & Common	117.3	32.2	(3.3)	146.2

It should be noted that the Peach Bottom totals include $19.1 million for the removal of the older, entombed Unit 1. This unit is included for two basic reasons. First, the NRC license at Peach Bottom cannot be terminated without removal of Unit 1 as well as Units 2 and 3. Second, the office facilities at Unit 1 are currently being used as the Technical Support Center, the remote Emergency Center and the Communications Center, and as such are an integral and necessary part of the Peach Bottom station. As shown, the Limerick 1 costs include the cost of common facilities shared with Limerick 2.

A comparison of the per-unit costs at each station (the Peach Bottom and Salem stations each have two units) exhibits both similarities and differences. A basic similarity is expected because the units at each station are in the 1055 to 1115 MWe capacity range. The differences between units arise because of reactor type differences, differences in sites, and differences between earlier and later designs of the same reactor type. The Salem reactors are pressurized water

reactor (PWR) types whereas both the Peach Bottom and Limerick stations use boiling water reactors (BWR). By its nature, the PWR tends to be built more into the ground than the BWR and therefore less of it must be physically removed to meet the "three feet below grade" removal criterion. Thus removal of a PWR tends to be inherently less costly than removal of a BWR. Moreover, in the case of Salem, foundation conditions required the establishment of a large and relatively deep foundation pad. As a result, Salem is even more below grade than is typical of PWRs, and its removal costs are even lower than is typical of PWRs relative to BWRs.

The similarity in per-unit decommissioning costs between the older Peach Bottom units and the newer Limerick unit, both of which are BWR's of almost identical capability, masks very real offsetting differences, which by coincidence almost cancel. At the older Peach Bottom station, the lower costs of removing the smaller quantities of equipment and materials used in the older plants is offset by the added cost, unique to Peach Bottom, of removing the cooling water canals and dikes built into Conowingo Reservoir, in order to restore state owned land to its original condition, plus the additional cost of removing the older Peach Bottom Unit 1.

Q. Please summarize the nuclear-related costs that were obtained and describe the basis for defining which costs are nuclear-related.

A. The following summarizes the nuclear-related cost of decommissioning the Company's Peach Bottom and Salem Stations and Unit 1 of the Limerick station:

Nuclear-Related Decommissioning Cost
in March 1984 Dollars
($ Millions)

Station	Removal	Disposal	Salvage	Total
Peach Bottom 2&3	144.1	61.6	(0.6)	205.2
Salem 1&2	115.7	44.6	(0.1)	160.2
Limerick 1 & Common	79.9	30.3	(0.5)	109.7

Again, the above costs for Peach Bottom 2 and 3 include an amount of $13.6 million for the nuclear-related portion of decommissioning the older Peach Bottom 1 unit at the same site. The Limerick 1 costs include the common costs shared with Limerick 2.

As previously mentioned, every item in the decommissioning data base is designated as nuclear or non-nuclear. The above nuclear-related decommissioning costs are the total of all cost items that have been designated as nuclear-related. The basic criterion for defining whether an item is designated as nuclear-related was established to be consistent with prior regulatory practice in the Commonwealth of Pennsylvania. The

original precedent was set by the Pennsylvania Public Utility Commission ruling on the allowable portion of decommissioning costs in 1978 (Pennsylvania Electric Company, 51 Pa P.U.C. at 669), and confirmed in subsequent ratemaking proceedings in connection with the decommissioning costs of Peach Bottom 2 and 3 and Salem 1. In the original Pennsylvania Electric ruling, the Commission did not allow those decommissioning costs that were for the dismantling of non-nuclear structures such as cooling towers, river water pump houses, and miscellaneous structures which by their nature pose no special concern in regard to health and safety. Thus, all equipment and structures which are not normally radioactive or are not likely to be radioactive because they do not contain or control radioactivity are designated non-nuclear, consistent with the original Pennsylvania Electric ruling. Specifically, all equipment and structures related to the cooling water system, including cooling towers and pump houses, and all equipment and structures related to the generation or off-site transmission of electricity are non-nuclear.

As was the case with total decommissioning costs, it should be noted that there are some system differences between BWRs and PWRs. In BWRs, the steam from the reactor goes directly to the turbine through moisture separators/reheaters and then through the condenser, the boiler feed pumps and feedwater

heaters back into the reactor. Thus, the turbine, the condenser and the feedwater system will be contaminated and require radioactive disposal. In the PWR, the water from the reactor passes through the steam generators where it boils water in the secondary system, which then goes to the turbine. However, because the reactor water is isolated from the secondary system, the turbine, condenser and feedwater system would not normally be contaminated. The net result of these differences is that somewhat less equipment requires radioactive packaging, shipment and disposal in the PWR than in the BWR.

Q. Please compare the nuclear-related decommissioning costs which you have just developed with those which were developed and used in previous Company rate proceedings.

A. The cost estimate utilized in prior proceedings was completed in mid-1979. It was performed by determining the major physical differences between the Company's Peach Bottom and Salem 1 units and the Diablo Canyon nuclear station for which a fairly detailed decommissioning cost estimate was available. These major physical differences were then translated into decommissioning cost differences and the decommissioning costs for Diablo Canyon were then adjusted by these differences to provide the decommissioning cost estimates for Peach Bottom 2 and 3 and Salem 1.

Because the Company is adding another nuclear unit at a new site, because the original estimates are now 6 years old and were not detailed, site-specific estimates and because consistency in cost estimating among units is considered essential, the Company has decided to develop the decommissioning cost estimates for all of its units on a detailed site-specific basis. Thus, the current estimates are considered to be more accurate than prior estimates because they are both more current and are now based directly on the sites and detailed designs of the Company's units. When the original 1979 estimate of the total costs of decommissioning of Peach Bottom 2 and 3 and Salem 1 is escalated to current dollar levels and compared to the new total estimate of Peach Bottom 2 and 3 (less Peach Bottom 1), plus 50% of Salem station estimate (for Salem 1), the results are about 12% below the current estimate. This difference is directly attributable to the greater detail of the current estimate.

A more significant difference is that the nuclear-related portion of the new estimate is about 73% of the total, whereas it was approximately 50% of the escalated total using the prior basis. In order to identify the source of this difference both the new estimate and the old estimate were examined. The new estimate is simply the total of all nuclear-related items and it was confirmed that the

designations of nuclear-related items were correct and consistent with the regulatory precedent established in the Pennsylvania Electric decision. The basic source of the difference is that the nuclear-related portion of the Diablo Canyon costs, used as the reference for prior work, were unusually low, for several reasons.

First, the original Diablo Canyon estimate included $30.5 million more for grading, backfilling and landscaping than will be required at the Company's sites. This additional cost is due to a requirement, at that particular site, to restore the site to the original contour as opposed to an acceptable contour. If this difference is removed, the nuclear-related fraction becomes 60% of the total.

Second, the original Diablo Canyon nuclear-related estimate omitted all but the radioactive disposal portion of the auxiliary building and the primary containment building, even though the equipment in these buildings is virtually all nuclear equipment, and the buildings themselves are designed to contain radioactivity releases and become partially radioactive themselves. Including the $10.6 million and $12.4 million costs for removing the auxiliary building and containment building respectively, as nuclear-related costs, raises the nuclear-related costs to about 74% of the total decommissioning cost. With the foregoing corrections, the

nuclear-related portions of the original estimate and the new estimate are consistent.

Q. Please describe the basis that has been developed for adjusting the March 1984 cost estimates to reflect the impact of present and future inflation on the costs of decommissioning.

A. The Commission has established the sound practice of collecting revenues based on current decommissioning costs and of maintaining the current purchasing power of accumulated funds that will be used to pay for future decommissioning. This requires that a realistic assessment be continually made of the impact of inflation. For this reason, the total and nuclear-related costs of decommissioning have been broken down into categories of cost for which reliable indicators of current and projected costs are maintained. These cost categories include craft labor, professional labor, equipment and material, waste disposal, and a number of other costs including energy, less credits for salvaged equipment and materials. The breakdown of total decommissioning costs into these categories is as follows:

Cost by Station
Millions of March 1984 Dollars

Cost Category	Peach Bottom 2 & 3	Salem 1 & 2	Limerick 1 + Common
Craft Labor, Skilled	86.970	62.655	43.581
Craft Labor, Common	39.459	26.266	17.996
Professional/Technical Labor	70.649	61.603	38.527
Equipment	38.466	25.494	17.468
Low Level Waste Burial	39.416	23.687	19.747
Salvage: Iron & Steel	(4.464)	(3.420)	(1.466)
Copper Scrap	(3.447)	(3.080)	(1.894)
Energy and Other	25.575	18.409	12.269
TOTAL	292.624	211.614	146.228

The breakdown of the nuclear-related decommissioning costs into these categories is as follows:

Cost by Station
Millions of March 1984 Dollars

Cost Category	Peach Bottom 2 & 3	Salem 1 & 2	Limerick 1 + Common
Craft Labor, Skilled	44.943	37.848	25.827
Craft Labor, Common	25.632	16.141	10.902
Professional/Technical Labor	57.484	50.239	31.762
Equipment	19.640	15.370	10.378
Low Level Waste Burial	39.416	23.687	19.747
Salvage: Iron & Steel	(0.577)	(0.064)	(0.563)
Energy and Other	18.647	17.003	11.622
TOTAL	205.185	160.224	109.675

Adjustments to the above costs to reflect June 30, 1986 conditions is discussed in the direct testimony of Richard W. Wright. I have reviewed Mr. Wright's escalation calculations and find them to be reasonable and consistent with the indicies suggested herein.

Q. Please describe the possible impact of NRC's recent proposed rulemaking on decommissioning.

A. The NRC published its long awaited proposed rule on "Decommissioning Criteria for Nuclear Facilities" in the Federal Register (Vol. 50, No. 28, Monday, February 11, 1985, Pg 5600). Comments have been requested and the final rule will be issued after comments have been considered. Thus, the rule is not final and is still subject to change.

The proposed rules were not issued until after my study was completed and therefore did not directly influence the assumptions used nor the approach taken in developing the Company's cost estimate. However, the proposed rules confirm the reasonableness of the Company's approach.

The proposed rules confirm the Company's proposed use of Prompt Decommissioning and express a preference for the site specific approach employed by the Company. The proposed rules also appear to confirm the general magnitude of the nuclear-related decommissioning cost estimate and the need for dealing with cost escalation. In particular, the NRC will require financial assurance that adequate nuclear-related decommissioning funds are being collected based on either a facility-specific cost evaluation or in the amount of $100 million (1984 dollars) per unit, to be escalated at a rate of twice the rate of change of the Consumer Price

Index. The Company's facility-specific nuclear-related cost estimates average less than $100 million per unit.

In this regard it should be noted that the proposed rule requires affected utilities to submit a decommissioning funding plan to NRC within 2 years, including both the decommissioning cost estimate and the method of funding. The NRC will review the plan as to the adequacy of both the nuclear-related decommissioning cost estimate itself, and the method of funding. A decommissioning cost basis which falls significantly below the $100 million level suggested by the NRC would face a correspondingly significant risk of NRC disapproval.

For these reasons, I believe the Company's estimate of decommissioning costs is fully consistent and supported by the NRC's proposed regulations.

Q. Does this complete your testimony?

A. Yes, it does.

ORIGINAL

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PHILADELPHIA ELECTRIC COMPANY

(Electric Division)

Direct Testimony

of

Joseph F. Brennan, President
Associated Utility Services, Inc.

Concerning

Fair Rate of Return

DOCKETED
SEP 27 1985

Table of Contents

Subject		Page No.
I.	Summary of Recommendation	1
II.	Description of PECO	3
III.	Capital Structure Ratios	6
IV.	Embedded Cost Rate of Long-Term Debt and Preferred Stock	9
V.	General Principles of a Fair Rate of Return	10
VI.	Relative Risk Analysis	11
VII.	Common Equity Cost Rate	15
	A. DCF Method	22
	1. Dividend Yield	26
	2. Growth Rate	27
	B. Risk Spread Analysis	35
VIII.	Common Equity Return Conclusion	39

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Joseph F. Brennan. I am President of Associated Utility Services, Inc., 155 Gaither Drive, Mount Laurel, New Jersey 08054. Associated is an independent consulting firm specializing in rate of return, financial, depreciation, cost of service, and valuation studies. Associated also performs utility rate case accounting, and special regulatory studies.

Q. WHAT IS THE NATURE OF YOUR ASSIGNMENT IN THIS PROCEEDING?

A. My assignment is to make an independent study and recommend an overall rate of return including a rate of return on common equity which Philadelphia Electric Company (PECO or the Company) should be afforded an opportunity to earn in connection with its application to increase its rates for retail electric service in Pennsylvania.

Q. HAVE YOU PREPARED AN EXHIBIT WHICH SHOULD BE MARKED FOR IDENTIFICATION?

A. Yes. Exhibit JFB 1, comprised of 17 Schedules, has been prepared by me or under my direct supervision.

Q. HAVE YOU PREPARED AN APPENDIX TO YOUR STATEMENT WHICH OUTLINES IN NARRATIVE FORM YOUR EDUCATION AND WORK EXPERIENCE?

A. Yes. It is attached as Appendix A.

I. Summary of Recommendation

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION IN THIS PROCEEDING.

A. I recommend that the Company be permitted a fair opportunity to earn an overall rate of return of 13.15% to 13.34% on its original cost rate base, including an opportunity to earn a 16.9% to 17.4% rate on the common equity portion of that rate base. This recommendation is based upon the Company's estimated capital structure ratios at June

30, 1986, the related estimated composite embedded cost of long-term debt and preferred stock, and an estimate of the cost rate for common equity reflective of the future. A summary of my recommendation is shown on page 1 of Schedule 1.

I have also calculated the overall rate of return for June 30, 1985. A summary of that calculation is shown on page 2 of Schedule 1.

On Schedule 2, I have shown a summary of the principal data I employed and the manner in which I employed such data in connection with my judgment as to the 16.9% to 17.4% opportunity cost rate for common equity.

Q. WHAT METHODS DID YOU EMPLOY IN DEVELOPING YOUR OPINION THAT THE PROPER OPPORTUNITY RATE FOR COMMON EQUITY CAPITAL SHOULD BE 16.9% TO 17.4% RELATIVE TO THE COMMON EQUITY PORTION OF THE ORIGINAL COST RATE BASE?

A. I employed two methods to arrive at my opinion, namely, a discounted cash flow (DCF) calculation and a risk spread analysis. I gave equal weight to the results of each method.

Q. WHY DID YOU ARRIVE AT YOUR OPINION BY GIVING WEIGHT TO THE RESULTS OF MORE THAN ONE METHOD?

A. Every method available to employ requires the exercise of judgment. Therefore, no one method should be employed to the exclusion of any other method in arriving at a judgment as to what is the market-required cost rate for common equity capital.

Q. DID YOU CONSIDER THE EMPLOYMENT OF METHODS OTHER THAN DCF AND RISK SPREAD IN ARRIVING AT THE COST RATE FOR COMMON EQUITY CAPITAL?

A. Yes. I observed earnings/price ratios, but only as a point of departure. Usually, an earnings/price ratio understates the market

required cost rate for common equity capital, particularly in the circumstance of investor-expected higher future earnings.

I also considered, but rejected, the use of capital asset pricing model (CAPM) calculations. I believe the CAPM is insufficiently reliable, primarily because CAPM is insufficiently company-specific.

I believe that DCF and the risk spread analysis methods to be more reliable and company-specific compared to other methods.

Q. WERE YOUR COMPUTATIONS IN REGARD TO DCF AND RISK SPREAD LIMITED TO PECO?

A. No. Primary weight in reaching an equity cost judgment should be given to cost data of the company whose rates are being set. However, I believe a conclusion derived from the company in question should be checked by reference to a barometer group of companies whose financial profile is the same or as similar to the company in question as is possible, recognizing the fact that the risk of investing in another company or group of companies is never identical to the company in question.

II. Description of PECO

Q. WILL YOU PLEASE DESCRIBE PARTICULARS PERTAINING TO PECO WHICH YOU HAVE EXAMINED IN DEVELOPING YOUR RECOMMENDATIONS.

A. The Company is an operating utility which provides electric and gas service to the public in southeastern Pennsylvania. Steam service is supplied in the central and west Philadelphia areas.

Two subsidiaries own, and a third subsidiary operates, the Conowingo hydroelectric project, and one distribution subsidiary provides electric service to the public in certain areas of northern Maryland adjacent to the project. The total area served by the Com-

pany and its subsidiaries covers 2,475 square miles; electric service is supplied in an area of 2,340 square miles with a population of about 3.7 million, including 1.6 million in the City of Philadelphia. Approximately 95% of the electric service area and 60% of the retail KWH sales are in the suburbs around Philadelphia and in northeastern Maryland.

The common stock of PECO is traded on the New York Stock Exchange. The bonds of PECO are now rated Baa3 by Moody's Investor Services, Inc. (Moody's) having been downgraded in late January 1983, BBB- by Standard & Poor's (S&P), and its preferred stock is rated "ba1" by Moody's and BB by S&P.

The Company spent approximately $1.053 billion for additions to utility plant including Allowance for Funds Used During Construction (AFUDC) during 1984. At December 31, 1984, construction work in progress of $4.187 billion was 145% of the $2.891 billion of book common equity. During 1985, the Company expects to spend about $1 billion for additions to utility plant.

Q. ARE THERE ANY SPECIAL CIRCUMSTANCES WHICH HELP EXPLAIN THE COMPANY'S ABOVE AVERAGE COST OF ATTRACTING CAPITAL AT PRESENT AND FOR THE FORESEEABLE FUTURE?

A. Yes. PECO's financial profile results in an investor judgment that the risk of an investment in PECO is significantly higher compared to the average operating electric company. The basis of my opinion in this regard is the fact that PECO's bond rating is the lowest of investment grades, its quality of earnings is much lower than industry averages (AFC expressed as a percent of net income to common equity), its non-cash earning assets (CWIP) expressed as a percent of book common equity are considerably higher than the industry

average, and its earnings/price ratio and dividend yield are considerably higher than the industry average. PECO's risk is even higher than a barometer group of companies whose financial profile is as similar as possible to PECO when employing the yardsticks I just mentioned (quality of earnings, bond rating, CWIP expressed as a percent of book common equity, earnings/price ratio and dividend yield). Moreover, there is uncertainty regarding completion of PECO's Limerick project.

PECO's earnings/price ratio (18.3%) and dividend yield (15.0%), based upon a market price of stock for September 19, 1985 are higher than the earnings/price ratio (15.6%) and dividend yield (11.9%) of the Barometer Group of Electric Companies whose bonds are rated Baa by Moody's, the same as PECO, and whose financial profile is relatively similar. The fact that PECO's earnings/price ratio and dividend yield are higher compared to the average earnings/price ratio and dividend yield for the barometer group of companies whose profile is similar, is not the product of a stock price aberration. The fact is PECO's earnings/price ratio and dividend yield have been consistently higher for several years. Moreover, PECO's stock price is and has been at a greater discount from book value compared to the barometer group, in spite of the fact that the PECO achieved earnings/book ratio is and has been higher than the earnings/book ratio for the barometer group of operating electric companies employed in my study.

I have explored reasons which may explain why the market requires a higher return for the use of common equity capital for PECO compared to the barometer group. One indication of the possible cause is the fact that PECO's Construction Work in Progress ex-

pressed as a percent of book common equity (about 145% at year-end 1984) is much higher than the average for the barometer group (about 111% at year-end 1984). A second possible reason is investor uncertainty and concern for the regulatory treatment to be afforded PECO in regard to its Limerick investment. The Commission's recent ratemaking treatment of Pennsylvania Power & Light Company (PP&L) apparently caused investors to consider the risk of investing in PECO to be higher compared to the risk prior to the recent PP&L decision.

Q. IS THERE ANY OTHER STATISTIC THAT MAY HELP EXPLAIN WHY INVESTORS BELIEVE AN INVESTMENT IN PECO IS MORE RISKY COMPARED TO THE INDUSTRY AVERAGE FOR THE BAROMETER GROUP COMPANIES INCLUDED IN YOUR STUDY?

A. Yes. PECO's revenue and sales mix is more heavily concentrated in the industrial sector than is the sales mix for the barometer group of companies included in my study. The risk of serving industrial customers is potentially more risky than is the risk of serving residential customers. In addition, the Philadelphia metropolitan area (PECO's primary service territory) is undergoing a transformation from a manufacturing center to a high-tech/office/financial center. Investors may consider possible further erosion in the industrial base of the service area as an above-average element of risk facing PECO and not faced similarly by the average electric company.

III. Capital Structure Ratios

Q. HAVE YOU PREPARED A SCHEDULE WHICH SHOWS THE COMPANY'S ACTUAL AND EXPECTED CAPITAL STRUCTURE AND RELATED RATIOS?

A. Yes. Information pertaining to PECO's actual capital structure and related ratios at June 30, 1985 and estimated at June 30, 1986 are

shown on page 1 of Schedule 3. Explanatory notes relative to the changes I have reflected and estimated to take place are revealed on page 2.

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE THE CHANGES AND ESTIMATES YOU HAVE EMPLOYED IN CONNECTION WITH THE DEVELOPMENT OF THE COMPANY'S JUNE 30, 1985 AND 1986 CAPITAL STRUCTURE AND RELATED RATIOS?

A. My starting point is the actual capital structure at June 30, 1985. Between June 30, 1985 and June 30, 1986, the total amount of debt and equity employed by PECO is expected to increase by almost $600 million. Details of the change are described in the notes on page 2 of Schedule 3. Some of the new issues planned include $100 million first mortgage bonds in November, 1985; $100 million of first mortgage bonds in May 1986; a $50 million new issuance of preferred stock in May, 1986; and approximately $170 million of new common stock. The end result of all the changes indicate that the Company's capital structure ratios at June 30, 1986 will be 50.7% long-term debt, 10.8% preferred stock, and 38.5% common equity. These ratios reflect a continuation of the positive trend that has been ongoing for the past few years, namely, the employment of less debt and more common equity. I have adopted the estimated June 30, 1986 capital structure ratios for rate of return determination purposes. Rate making is and should be prospective. These ratios are more indicative of the future than the actual June 30, 1985 ratios. These ratios are prudent and well within the range of ratios employed by other operating electric companies.

Q. DO YOU BELIEVE THE MANAGEMENT OF A UTILITY HAS THE RIGHT TO CHOOSE THE TYPE OF CAPITAL IT WILL EMPLOY TO FINANCE ITS INVESTMENT IN ASSETS?

A. Yes. I believe management has the right to choose the way its assets are financed. My opinion extends to public utility companies with the caveat that management's choice should be employed by the regulatory agency having jurisdiction with respect to establishing the authorized price of service, so long as management's choice is prudent and not unreasonable.

There is no one ideal capital structure, even for a particular company, that is appropriate all of the time, given changing money market circumstances and changing business risk affecting the enterprise. However, I do believe there is a range of appropriate capital structure ratios which, for a utility, can be viewed as ideal, keeping in mind that the criteria of prudence must be observed, given the utility's obligation to render service to the public all of the time, rather than some of the time, in the interest of consumers and the economic well-being of the area served by the utility. Further, since rate making is prospective, I believe the capital structure ratios appropriate to employ for rate of return determination purposes are ratios indicative of the future, the period of time the rates for service in question will be in effect. Lastly, in the circumstance of increasing business risk and the inability to necessarily change ratios quickly, given adverse financial circumstances, I also believe it appropriate to move toward objective capital structure ratios reflective of changing business risk.

Q. WHAT ARE PECO'S OBJECTIVE CAPITAL STRUCTURE RATIOS?

A. I have been informed by management that the Company believes at this time it is proper and appropriate to maintain a common equity ratio which will average approximately 38%, a debt ratio of 50%, with

preferred stock providing the balance of permanent capital. These ratios are very close to the ratios expected at June 30, 1986.

IV. Embedded Cost Rate of Long-Term Debt and Preferred Stock

Q. WHAT IS THE ACTUAL EMBEDDED COMPOSITE INTEREST RATE FOR PECO'S LONG-TERM DEBT AT JUNE 30, 1985, AND AT JUNE 30, 1986 ON AN ESTIMATED BASIS?

A. The actual composite long-term interest rate at June 30, 1985 is 10.74%. Detailed calculations are shown on Schedule 4, pages 1-4, inclusive.

The estimated composite long-term interest rate at June 30, 1986 is 10.84%. Details of this calculation are shown on Schedule 4, pages 5-8, inclusive.

The 10.84% estimated composite interest rate at June 30, 1986 reflects: (a) the 10.5% interest rate actually paid relative to a $245.0 million Pollution Control Note issue sold in May 1985; (b) an assumed 12.5% interest rate relative to two $100 million first mortgage bond sales planned for November 1, 1985, and May 1986. The basis of the 12.5% assumed interest rate is explained in Note 7, page 3, Schedule 6. Prior to the time the record in this case is closed, I will provide the actual cost rate related to this issue and reflect that cost rate in an update of the development of the composite cost of long-term debt.

Q. WHAT IS PECO'S ACTUAL AND ESTIMATED EMBEDDED COMPOSITE COST RATE OF PREFERRED STOCK AT JUNE 30, 1985 AND 1986, RESPECTIVELY?

A. The actual composite cost rate at June 30, 1985 is 10.42%. The estimated composite cost rate at June 30, 1986 is 10.54%. Information pertaining to the development of these composite cost rates is shown on Schedule 5, pages 1 through 4.

In arriving at the estimated June 30, 1986 composite cost rate, I have assumed a cost rate of 12.5% relative to the $50 million preferred stock planned to be sold in October, 1985. The basis of my opinion as to a 12.5% dividend rate relative to the $50 million planned preferred stock sale is the fact that when PECO has sold bonds and preference stock at about the same time, the interest and dividend rate was similar. I plan to provide the actual preferred stock cost rate prior to the time the record in this case is closed.

V. General Principles of a Fair Rate of Return

Q. WHAT IS THE ROLE OF MARKET DATA IN THE DETERMINATION OF THE COST OF COMMON EQUITY?

A. Market data are essential in such analyses. The cost of common equity should be derived from market information. The cost of equity is not what theorists, regulators or company management believe it should be, or what they would like it to be, but what the money market says it is. A utility has no monopoly in the money market. Capital cannot be conscripted. Capital is hired in the money market. Thus, the relevant information to study and analyze is money market related or derived information.

In my opinion, only if marketplace data are employed can the regulator ensure, over the long run, the utility's ability to meet its service obligations. Assurance of adequate service can only be achieved if earnings are sufficient to permit (1) the attraction of an adequate amount of capital at a reasonable cost, and (2) the maintenance of the integrity of presently invested capital. These standards for a fair rate of return have been well established by the U.S. Supreme Court in the Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n, 262 U.S. 679 (1922) and Federal Power

Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

In an unregulated competitive environment, price for service is established in the marketplace. In the utility situation, prices are set by regulatory agencies. For that reason, regulatory authorities must function as a substitute for the marketplace in setting the price of service consistent with the need to provide service over the long term. Therefore, prices for service should be set to provide the utility with an opportunity to recover all costs, including a fair rate of return on capital supplied by investors.

VI. Relative Risk Analysis

Q. WHY IS IT NECESSARY TO ANALYZE RISK IN THE DETERMINATION OF THE COST OF COMMON EQUITY?

A. The investors' perception of the relative risk in alternative investments is the very essence of the market-determined return required from those investments. An investor in common equity is buying the right--that is, acquiring an ownership interest--to an income stream represented by the earnings of the company. If investors perceive that there is considerable risk in realizing the expected income stream, they lower the price they are willing to pay, thereby increasing the rate of return. If, on the other hand, they perceive that the income stream is stable and assured, they will be willing to pay a higher price for the rights of common equity ownership, thereby reducing the rate of return. Therefore, an analysis of company specific risk which includes service territory and regulatory risk is a very basic element in the determination of the market-required cost of common equity.

Q. WHAT RISK FACTORS AFFECT INVESTOR JUDGMENT?

A. There are two principal factors, business and financial risk. The sum of business and financial risk is commonly referred to as investment risk. Business risk encompasses all the risks of a firm as if it were financed entirely with common equity capital. Financial risk is the added element of risk resulting from employment of fixed-cost investor provided capital, such as debt or preferred or preference stock. The presence of debt, preferred, or preference stock in the capital structure is referred to as financial leverage. The use of leverage (the use of debt and preferred stock) decreases the revenue cost of capital to consumers in the utility situation, but increases the risk to the common stock investor. In the non-utility situation, the common stock investor can receive all of the benefits of the use of leverage. However, in the utility situation, rate regulation passes on to consumers a large part of the benefits of the use of leverage in the form of a lower cost of service (lower income tax expense and use of embedded cost of debt and preferred stock for rate of return purposes).

Q. IS THERE AN INTERRELATIONSHIP BETWEEN BUSINESS AND FINANCIAL RISK?

A. Yes. The presumed amount of business risk present in an enterprise influences the manner in which that enterprise should be financed. A higher degree of business risk generally requires the employment of less financial leverage (the employment of less fixed cost capital, such as debt and preferred stock) and thus more common equity. A utility must be in a position to meet all customer demands for service over the long run in order to fulfill its service obligation. In the non-utility situation, there is no similar obligation to serve or increase capacity to serve. The choice of capital structure, or the degree of financial leverage

employed, can help to offset the business risk of an enterprise in terms of capital attracting ability. Ideally, a utility would employ a capital structure which would permit the attraction of capital at a cost rate no higher than an investment grade non-utility. In fact, unfortunately, the attraction rate for utility debt is higher than the attraction rate for non-utility debt, as can be seen by reference to the information shown on page 1, Schedule 6. If debt costs more, common equity also costs more. These data suggest utilities should strive to employ more equity and less debt to be more competitive in the capital markets.

It should be noted that while the cost rate for utility debt and equity capital may be more than the cost rate for non-utility debt and equity capital, the overall cost of capital for most utilities is less than is the overall cost of capital for non-utilities because utilities employ more debt (which costs less than equity) and less equity (which costs more than debt) compared to non-utilities.

Q. IS THERE EVIDENCE THAT THE CAPITAL MARKETPLACE GIVES RECOGNITION TO THESE RISK PERCEPTIONS?

A. Yes, the capital marketplace is driven by investor perceptions of risk. One of the best examples is bond ratings. Rating agencies, such as Standard & Poor's (S&P) evaluate the creditworthiness of the fixed income securities of many businesses. These ratings reflect perceptions of the relative risk associated with a particular security. The criteria for S&P ratings are generally known and involve consideration of factors relating to both the business and financial risk of the issuing company.

Investors rely on the qualitative judgments of the rating agencies, as evidenced by the yield basis upon which they purchase variously rated bonds. Investors require higher returns for bonds of poorer quality (high risk) and lower returns for those of higher quality (low risk). This evidence, as shown on Schedule 6, demonstrates that investors do, in fact, base their investment decisions on considerations of business and financial risk, which when considered together, is referred to as an investment risk.

Q. WHAT IS YOUR OPINION WITH RESPECT TO INVESTOR PERCEPTION OF THE RELATIVE INVESTMENT RISK DIFFERENCES BETWEEN NON-REGULATED FIRMS AND REGULATED UTILITIES?

A. Historically, investors believed utility service to be a lower business risk endeavor compared to many non-utility companies. This relatively low business risk permitted the use of greater financial leverage. The risks of large capital commitments for long periods of time, actual or potential competition, potential long-range shortages of natural resources (at competitive prices), inflation, and rate regulation influence the choice of the financial leverage employed by utilities. The investment risk for utilities has risen compared to non-utilities. Indeed, the investment risk for some utilities is as much or more compared to some non-utilities.

Responses to increased business risk must ultimately be higher achieved earnings, less financial leverage (less debt and more equity) or a combination of both, so that the investment risk is at parity with other utility and non-utility companies.

Q. ARE CHANGES IN INVESTMENT RISK CAUSE FOR CHANGES IN INVESTOR ATTITUDES?

A. Yes. The business risk of non-utilities is implicitly affected by investors' perception of actual or potential volatility of revenues, expenses, and hence earnings. Non-utilities are affected by both competition from purveyors of the same product or a close substitute and the possibility that their product or service will no longer be needed or wanted by society. Non-utility companies generally have been able to either achieve adequate earnings or present a profile which commands investor confidence of an adequate earnings expectation, as evidenced by a stock price consistently above book value and as is evidenced by the fact that non-utility companies actually pay less to attract long-term debt of investment grade compared to utilities, as shown on page 1 of Schedule 6.

Utility companies must achieve investment standing in the minds of investors similar to that enjoyed by non-utility companies because utilities do not enjoy a monopoly in the money market. Utilities must compete for capital with all other seekers of capital. Capital flows to the endeavors with the highest return opportunity commensurate with the risk to which the capital is exposed.

VII. Common Equity Cost Rate

Q. WHAT INFORMATION DID YOU STUDY AND CONSIDER IN ARRIVING AT YOUR JUDGMENT AS TO THE COST RATE FOR COMMON EQUITY CAPITAL FOR PECO?

A. I observed historical interest rate trends and forecasts of interest and inflation rates. This information is shown on Schedule 6.

I observed several different financial ratios specific to PECO and the average for a barometer group of operating electric companies similar but not identical in risk to PECO. This information is shown on Schedules 7 through 11, inclusive.

Please note by reference to Schedule 7 that the achieved earnings rate on book common equity for PECO was 12.9%, or higher than the 12.6% average for the barometer group for the five years ended 1984. Please also note that the achieved rate of return on average book common equity for PECO and for the barometer group of companies has moved up significantly during the past five years. Specifically, as to PECO, the 1984 ratio of 15.1% and the spot 1985 rate of 15.1% was considerably higher than the 12.9% average for the five years ended 1984 or the 10.6% for the year 1980. The experience for the barometer group was similar in terms of upward movement. Accordingly, it is fair to say investors may perceive a prospective rate of growth in earnings and dividends higher than the average for the past five years. This is fair to say in light of the fact that the current rate of earnings is lower than the 15.7% and 16.7% rate authorized by the regulatory authorities which have jurisdiction as to the barometer group and PECO, respectively.

Q. ARE YOU AWARE OF THE FACT THAT THIS COMMISSION, IN ITS LAST ORDER PERTAINING TO PECO, OFFERED THE OPINION THAT IT IS NOT REALISTIC TO ASSUME INVESTORS EXPECT TO ACHIEVE A RATE OF EARNINGS ON COMMON EQUITY MEASURED AT BOOK COST EQUAL TO WHAT A REGULATORY AUTHORITY INTENDED?

A. Yes. If this Commission believes the price of service they authorize will not produce the rate of earnings on the common equity part of the rate base they intend, then an attrition allowance is required if this Commission intends to comport with the teachings of the United States Supreme Court in the landmark Hope and Bluefield cases. A utility is entitled to an opportunity, but not a guarantee, to experience a rate of earnings, which will, among other

things, produce a value of stock at least equal to the rate base value. For the past several years, PECO and many other utilities have not experience a rate of earnings sufficient to motivate the marketplace to price stock equal to or slightly above book value. At this time, PECO's common stock still sells at a discount from book value, whereas the average electric company stock price is near or above book value. There has been a marked upward movement in PECO's achieved rate of earnings on book common equity. I believe investors expect that trend will continue until the point is reached when PECO in fact earns a rate of earnings equal to that intended by this Commission.

On Schedule 8 I have shown the relationship of the market price to the book value for common equity for PECO and the average for the Barometer Group of Electric Companies included in my study. Please note that for the five years ended either 1979 or 1984, the average market price was less than book value. However, for a spot point in time in 1985, the ratio moved up, coincidentally, as the achieved rate of earnings increased. For the Barometer Group of Four Electric Companies whose bonds are rated Baa by Moody's, as are the bonds of PECO, the market price of stock in 1985 is 95.0% of book value, while the market price of PECO stock moved up to 82.2% of book value at a time when the achieved rate of earnings on average book common equity moved up to 15.1%.

The information shown on Schedule 9 is the development of a market-price index for the price of stock and the movement of that stock price from 1974 through 1985 at a spot moment in time. This information facilitates a comparison of the movement in the market price of stock for one company to another or a group of companies.

I have also shown a similar calculation with respect to the average book value of common equity per share. The PECO index, in regard to both the market and the book value, was lower than the average for the barometer group and a broader group of utility companies, the Dow Jones Utilities.

For clarification, it should be stated that the achieved earnings/book ratio of a particular year or a moment in time is not necessarily the driving force relative to the market price of stock for the same year or moment in time. The market price of stock is reflective of investors' expectations of the achieved rate of earnings in the future which may be higher or lower than the achieved earnings rate on book common equity of the moment or for a given year or period of years. In the circumstance of PECO, as I will explain later, earnings growth is expected based on both projections of investment advisory services and as indicated by historic experience.

The information shown on Schedule 10 reveals earnings/price ratio information. The earnings/price ratio is the relationship of reported earnings per share relative to the market price of the stock. The earnings/price ratio may result in an understatement or an overstatement of the investor-required rate of earnings. The basis of this statement is the fact that the ratio is essentially a mismatch in that the price of stock is reflective of investor expectations of future earnings and the earnings rate, but the earnings used in the computation are historic. Please note by reference to Schedule 10 the fact that the spot earnings/price ratio for PECO at 18.3% is higher than the spot 15.6% earnings/price ratio for the Barometer Group of Operating Electric Companies included in my

study. Please also note the fact that for the five years ended 1984, the earnings/price ratio for PECO was 16.8%, while the average earnings/price ratio for the Barometer Group of Operating Electric Companies during the same period in time was also 15.4%. The data suggest an investor perception of a higher risk, and hence, higher cost rate for common equity for PECO compared to the barometer group, notwithstanding the fact that PECO's bonds carry a similar rating to the bonds for the barometer group.

The information shown on Schedule 11 shows the common dividend yield and the common dividend payout ratio for PECO for the five years ended 1984 and a spot point in time mid-1985. These data indicate the Company's dividend yield and dividend payout ratio is higher than the average for the barometer group companies. This information suggests a market expectation of a likely lower growth rate in the value of PECO's stock compared to the barometer group of companies included in my study. As I will discuss later, historic, as well as forecasted, earnings and dividend growth confirm this expectation.

On page 1 of Schedule 12 I have shown PECO's capitalization and financial statistics for the years 1980 through 1984.

Total capital employed by PECO increased from $4.9 billion in 1980 to $8.2 billion in 1984, or an increase of over 66%.

Shown on the lower part of page 1 of Schedule 12 are interest and overall coverages as well as financial ratios indicative of quality of earnings. The quality of PECO earnings is very low, as indicated by AFC expressed as a percent of net income to common equity (average of 84% for the years 1980 to 1984, almost 87% for 1984, and as indicated by an effective income tax rate which

averages just 21% for the five years ended 1984, and 21% for 1984). By comparison, similar information shown on Schedule 13 pertaining to the barometer group also indicates low quality of earnings, but not as low as PECO. For instance, the PECO 87% AFC expressed as a percent of net income to common equity for 1984 is worse than the indicated 75% for the barometer group. What this ratio means is that with a 15.1% rate of earnings on the book value of common equity for PECO, but with 87% attributed to AFC, the cash return on book common equity provided by consumers is but 2.0% (the complement of 87% is 13%, and 13% x 15.1% is 2.0%). Moreover, in regard to interest coverage, computed excluding AFC, the PECO coverage for 1984 was but 1.6 times, or worse than the 1.8 times indicated for the barometer group for 1984.

On pages 3 and 4 of Schedule 12 I have shown the results of an analysis of PECO's public offerings of common stock during the years 1980 through 1984. Please note by reference to page 3 the fact that at no time during the five year period was the company able to realize a net proceeds per share equal to per share book value when new stock was sold. Given the fact that the Company's current market-to-book ratio is 82%, and given an assumption of a continuation of the upward movement in the achieved rate of earnings on average book common equity, it seems reasonable to conclude that prospective new stock sales may net a price close to book value. Of course, if the authorized rate of return on book common equity is less than the market requires, the price of stock could remain below book value.

On page 4 of Schedule 12, I have shown the fact that the sum of issuance and selling expenses expressed as a percent of the offering

price of new common stock sold during the years 1980 to date, inclusive, averaged 3.16%.

Q. WHAT DOES THE INFORMATION SHOWN ON PAGE 4 OF SCHEDULE 12 SUGGEST?

A. This information suggests the need to experience an earnings rate on book common equity which would result in a market price of stock 3% above book value so that when new shares of stock are sold, as is contemplated by PECO, the net proceeds would at least equal book value and no dilution would take place.

There is no provision in the ratemaking process to recover issuance and selling expenses when new shares of stock are sold, other than to reflect the impact in the development of the cost rate for capital. Therefore, unless the authorized rate of earnings on common equity reflects the impact of issuance and selling expenses, such costs go unrecovered.

I am aware of the fact that this Commission has not allowed specific recognition of the impact on the cost rate for common equity capital occasioned by issuance and selling expenses related to the sale of new common stock. The Commission does routinely recognize, as do most other Commissions, the impact on the cost rate of issuance and selling expenses related to the sale of long-term debt and preferred stock. Further, I believe the Commission's policy is inconsistent with the philosophy of cost-based ratemaking and the philosophy that the regulated price for utility services is intended to be a substitute for a price of service established in the marketplace. All costs that are known and measurable should be recognized in the development of the revenue requirement. Issuance and selling expenses are known and measurable. I urge the Commission to change its policy in this regard so that investors truly

have an opportunity to recover all costs and experience a rate of earnings on common equity sufficient to result in a market price of stock at least equal to book value on a sustaining basis.

Q. PLEASE DESCRIBE THE INFORMATION SET FORTH ON SCHEDULE 13.

A. The information shown on Schedule 13 pertains to the Barometer Group of Four Electric Companies similar in risk to PECO. The basis of selection, the names and the bond and preferred stock rating of each of the barometer group companies, is shown on page 2. I have shown capitalization and financial statistics for the years 1980 through 1984, inclusive, the latest five full calendar years available for all companies included in my study, similar to the information shown on page 1 of Schedule 12 pertaining to PECO.

For comparative purposes and to obtain insight with respect to risk differences between PECO and the Barometer Group, I also observed data pertaining to operating revenues, electric sales, and customer and generating mix. This information, together with other data previously discussed, indicates some similarity between PECO and the barometer group. However, money market data reveals PECO's cost of capital is higher compared to the barometer group. Thus, the use of the barometer group as a proxy for PECO would understate the common equity cost rate to PECO.

A. DCF Method

Q. WOULD YOU BRIEFLY DESCRIBE THE DCF TECHNIQUE?

A. The DCF technique is based on an analysis of publicly traded common stock. It is a technique which utilizes the market price, reported earnings per share and dividend payments per share in a calculation to determine the implicit return required by the investor and reflected in the market price of the stock.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF TECHNIQUE?

A. An investor who agrees to purchase common stock at a given market price is purchasing the rights to an income stream. That income stream includes the present and anticipated earnings of the Company, the portion of those earnings that are currently and prospectively being paid out in the form of dividends, and the proceeds from the ultimate sale of the stock at some future market price.

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

Based on all these considerations, the investor agrees to pay a given market price for the stock at a given moment in time. Presumably, that market price represents the present value of that anticipated income stream, at some discount rate. The DCF technique is an analysis which combines a market price with projected dividend and earnings growth rates to arrive at a discount rate, which reflects the return required by the investor at the time of purchase.

Q. CAN YOU PROVIDE AN ILLUSTRATION OF THE DCF TECHNIQUE?

A. Yes. First, assume that a company's common stock sells at $10 a share and the book value is also $10 a share. For simplicity, assume that the reported earnings per share are $1 and that dividends are $.50. Such data suggests that the dividend yield is 5% ($.50 relative to $10 price), and that the stock sold at 10 times earnings ($10 purchase price ÷ $1 earnings). It can be computed that if the

$.50 retained earnings (the complement of the $.50 dividend, given $1 of reported earnings) earns at the same rate of return as the total common equity of the enterprise, the growth rate in earnings, dividends and book value would be 5% (assuming the dividend payout ratio does not change and any new stock sales are at book value). The sum of 5% growth and 5% dividend yield is 10% by the application of the academic version of the DCF. These computations assume that there is no change in the price/earnings multiple. Recognizing that price/earnings multiples do change and are taken into account by investors and investment advisory services, it is my opinion that it is inappropriate, for rate of return regulation, to rely solely on a DCF cost of equity.

Q. DOES THE TYPICAL DCF COMPUTATION INCLUDE THE ASSUMPTION THAT INVESTORS USE A SINGLE GROWTH RATE FOR THE INFINITE FUTURE?

A. Yes.

Q. IS THAT A REALISTIC ASSUMPTION?

A. No. While the typical DCF model proceeds from the premise that the rate of growth reflected in the price of stock is a particular rate over time, in fact, the growth rate can vary from period to period.

For instance, if a utility company is earning less than its allowed return, investors may believe the rate of growth over the course of the next few years is related to the intended earnings rate on the book value of common equity. Under such circumstances, growth in earnings and dividends, and hence stock value, is enhanced by an upward movement in the rate of earnings until the allowed rate of earnings is realized. Such growth, however, is transitional and not sustainable. Moreover, the rate of earnings and dividend growth under DCF theory will be identical when the intended rate of ear-

nings is attained. At that time, a sustainable growth rate will be experienced, assuming, as DCF theory requires, no change in payout ratio. Further, the value of stock will grow at the sustainable rate assuming, as required by DCF theory, no change in price-earnings multiples. Accordingly, the rate of growth reflected in the price of stock under the circumstances I have described is not just the sustainable growth rate, but the product of both transitional and sustainable consideration.

Q. HAVE YOU PERFORMED DCF CALCULATIONS FOR PECO AND THE BAROMETER GROUP OF ELECTRIC COMPANIES INCLUDED IN YOUR STUDY?

A. Yes. I have performed a single-stage DCF calculation for PECO and for the barometer electric company group included in my study. The single-stage DCF model assumes a constant growth rate over the entire time horizon. As previously indicated, a two-stage model recognizes a different growth rate in the near term (transitional) than that expected in the long term (sustainable). While I have not sponsored a two-stage DCF calculation in this case, I have performed a two-stage calculation, and such calculation indicates a significantly higher PECO common equity cost rate compared to the single-stage calculation. I have not shown nor used the two-stage calculation to form a judgment because in the circumstance of PECO there is investor uncertainty regarding the earnings capacity of a large part of its book common equity. A two-stage calculation, which assumes investors reflect in the price of stock an eventual rate of earnings on book common equity equal to the PUC authorized rate on rate base common equity may overstate the cost rate for common equity.

Using the single-stage methodology produces a DCF derived cost rate for PECO of 16.7%, before any impact of issuance and selling expenses. For the Barometer Group of Operating Electric Companies with bonds rated Baa, the single-stage DCF calculation indicates but a 15.0% cost rate before impact of issuance and selling expenses.

1. Dividend Yield

Q. WHAT DIVIDEND YIELD DO YOU USE IN DEVELOPING THE COST OF COMMON EQUITY?

A. I adopt a 15.0% yield for PECO and a 12.1% yield for the four company barometer group.

Q. HOW DID YOU DEVELOP THESE DIVIDEND YIELDS?

A. I believe the price of common stock is reflective of the next period dividend, a requirement of the DCF model when the dividend is paid discretely rather than continuously. However, there are no empirical studies which prove that investors always expect the next period dividend and reflect that estimate in the price of stock. Thus, it is possible that the price of stock is reflective of the current annualized dividend. Moreover, the current dividend yield, which is the product of a stock price of a particular day, is sometimes distorted because that price may be abnormally high or low and not representative of the future. Thus, the dividend yield used for DCF purposes should be the product of not just the current price of stock, but also an average price over a recent period of time, such as twelve months. This approach likely will be more representative of the future over time, since price abnormalities and trends will tend to be moderated by the use of both the current and a twelve month average price of stock to develop the dividend yield for DCF calculation purposes.

Given the various interpretations of the appropriate dividend yield, I have incorporated a number of methods of calculating yields in my DCF analysis. On page 1 of Schedule 14, I show the spot dividend yield, based upon the price of stock on September 19, 1985, and the dividend yield for the twelve months ended August 31, 1985, for PECO and for each company included in my study. I have also shown the next period dividend growth rate and a calculation of the dividend yield reflecting growth based upon September 19, 1985, and the average twelve months ended August 31, 1985 price of stock. In the last column, I have shown the arithmetic average of the September 19, 1985, and the twelve months ended August 31, 1985 dividend yields with and without regard to the next period dividend growth. The end result is, in effect, recognition of half the next period dividend growth in the dividend yield calculation.

For clarification, it should be stated that the next period dividend growth rate reflected in the calculations to which I have just referred is the average of Merrill Lynch and Value Line projected dividend growth rates and the historic growth rate, all as shown on Schedule 15, page 1.

2. Growth Rate

Returns in the equity market are provided by the receipt of dividends and through capital appreciation of the investment. As a measure of the capital appreciation potential of an equity investment, the expected growth in earnings per share and dividends per share provide one indication of the DCF growth component. Since DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings. Within this context, some of the factors which contribute to expected earnings

growth are: (i) the earnings rate on existing equity; (ii) the portion of earnings not paid out in dividends; (iii) sales of additional common equity; (iv) reacquisition of common stock previously issued; (v) changes in financial leverage; (vi) acquisitions of new business opportunities; and (vii) profitable liquidation of assets.

To assess future growth prospects, investors may consider both historic experience and projected future growth rates in formulating expectations. An investor can compute historic growth rates using compound growth rates or growth rate trend lines using past period reported financial variables. Otherwise, an investor can rely upon published future growth rates as provided in widely circulated and influential publications. It is important to remember that the common equity cost rate is expectational, and, as such, ex ante data is important to consider when quantifying investor return requirements. It should be noted, however, that the realities of the equity markets regarding total return expectations also reflect factors, such as changing price-earnings multiples, other than the inputs usually considered in the context of a DCF growth rate. The pertinent point of consideration is to determine what influences investors' perception of future growth. The forecasts of investor advisory service are influencing, as found by Cregg and Malkiel, "Expectations and the Structure of Share Prices," University of Chicago Press, 1982, Chapter 2, and others.

One influential publication in this regard is the Value Line Investment Survey which contains projections of growth. A September 20, 1983 Wall Street Journal article indicated that Value Line subscriptions have increased to 133,700, with individual investors

representing the bulk of the subscribers. This certainly indicates that Value Line projections of growth for the future have an influence on investor expectations.

The Value Line Investment Survey provides comprehensive coverage of nearly 1,700 firms. Growth estimates by Value Line are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy.

Forecasts of earnings and dividend growth are also available from securities brokerage firms. The largest of these securities brokers is Merrill Lynch, which has 9,900 account executives in 523 offices worldwide. The Merrill Lynch Investment Strategy Department publishes projected earnings and dividend growth rates for nearly 1,000 firms including close to over 100 utilities. Merrill Lynch has been reviewing and evaluating utility common stocks for many years. Merrill Lynch publishes projections for utilities in Quantitative Analysis - Common Stock Valuation. This publication is widely available to investors free of charge.

There are numerous other sources of projections of utility earnings and dividend growth. However, these are less readily available to the average investor. The majority of utility common stock is held by individual investors as set forth on page 2 of Schedule 15 (only about 16.0% of PECO common stock and about 21% as an average for the barometer group companies included in my study, is owned by institutional investors). Individual investors typically have small holdings and have limited resources available to acquire advisory services.

In addition to investor-influencing publications, equity investors may also rely upon the observations of past performance. Investors' expectation of future growth rates may be determined, in part, by the observation of historical growth rates. The historic dividend growth rate is usually more stable than an historic earnings growth rate given the practice of most utilities who are loath to reduce or eliminate dividends due to earnings adversity. This attitude is likely the product of the observation of market behavior when utility dividends have been reduced or eliminated, even when such reductions or eliminations have been temporary in nature. When a utility dividend reduction or elimination occurs, or even the threat of reduction or elimination is present, a significant stock price reduction occurs, which in turn results in a significantly higher cost to attract capital.

For all of the reasons cited above, I believe the growth rate reflected in the price of electric utility stock is the product of both historic and forecasted growth rates. Between the two, I believe forecasted data is more investor-influencing, if for no other reason than the average investor is aware that the future likely will be different from the past. However, as previously stated, there is no empirical evidence that investors give exclusive weight to projected or historic data or unequal weight to each. However, my testing of both Value Line and Merrill Lynch forecasts of earnings and dividend growth and of historic earnings and dividend growth reveal that the forecasts over the course of the past four years better indicate the percent change in value of stock which is, of course, the "g" part of the DCF model (see Schedule 15, page 3). I therefore believe rational investors would not give as

much weight to historic data in these circumstances. Accordingly, I have used both projections and historic data to form a judgment as to the growth rate reflected in the price of stock, but have given greater weight to forecasted data. As explained below, this greater reliance on forecasted data lowered the growth rate I employed for PECO.

Q. WHAT GROWTH RATE DO YOU BELIEVE INVESTORS EXPECT WITH RESPECT TO THE VALUE OF THE COMMON STOCK FOR PECO AND THE ELECTRIC COMPANIES INCLUDED IN YOUR STUDY?

A. I employed a growth rate of 1.7% for PECO and 2.9% as the average for the barometer group. The details of the precise growth rates I employed are shown on page 1 of Schedule 15. I employed the average of forecasted earnings and dividends growth derived from Merrill Lynch and Value Line publications. The projections are for a five year period. I also employed historic dividend growth based upon the past five years. It should be noted that if I had employed both historic earnings and dividend growth rates reaching back five years, rather than just historic dividend growth, the growth rate would be higher than the growth rate I did employ with respect to PECO (2.2% instead of 1.7%) and for the group of companies (3.3% instead of 2.9%). Similarly, had I given equal weight to historic and projected data, my growth rate for PECO would have been higher (2.9% instead of 1.7%).

Q. WHAT PERIOD OF TIME IS APPROPRIATE TO EMPLOY IN REGARD TO GROWTH RATES?

A. The historical growth rate period I employed is the most recent five year period. The Securities and Exchange Commission (SEC) requires five years historic data be shown in prospectus when public sale of

securities take place. The role of the SEC is to make certain investors are provided adequate, accurate and complete information pertaining to the sale of securities to the public. In addition, extending my analysis to more than five years into the past for guidance pertaining to 1985 and beyond would ignore fundamental changes in the economy, the electric industry, and PECO. In my judgment, if investors look back in time for guidance with respect to the future, the period given most weight would be no more than the past five years.

With respect to projections of growth, I believe the price of stock is the product of an average investment horizon of no more than five years. The basis of my opinion is the fact that common stock turnover rates for PECO and the barometer group included in my study, as well as electric companies in general, have been trending downward for several years to the point where the turnover rate is now indicated to be less than three years. The average investment horizon, as indicated by share turnover rates for the five years ended 1984 for PECO and the barometer group, is about four years, but for the year 1984 it is less than three years compared to more than five years in 1980.

The turnover rate to which I refer is a calculation of the number of shares traded each year for each company divided into the number of shares outstanding to indicate how many years of trading it takes for the stock to turn over once. This calculation gives insight with respect to what is the average investment horizon or time frame stock is typically held by the average investor. Information pertaining to turnover rates is shown on page 2 of Schedule 15.

Q. WHY HAVE YOU NOT EMPLOYED AS AN INDICATOR OF GROWTH RATE BOOK VALUE GROWTH RATES OR THE RETENTION RATIO TIMES THE ACHIEVED OR HISTORIC EARNINGS/BOOK RATIO?

A. The retention ratio times the achieved or historic earnings/book ratio or so-called "b x r" growth rate is a method which proceeds implicitly from the premise that the growth rate reflected in the price of stock is infinite. When the DCF methodology was first invented many years ago, it may have been appropriate to assume that investors purchased stock with an infinite time horizon. However, as I just indicated, the reality of the real world at this time is an investor's time horizon less than five years. Accordingly, if the investment horizon is less than five years, I believe it inappropriate to proceed from a premise for which there is absolutely no support, namely an infinite investor horizon as indicated by "b x r" approach. Moreover, with respect to historic growth rate in book value or the historic "b x r," such data may misstate the growth reflected in the price of stock by investors today and prospectively. For instance, investors are aware that the historically achieved earnings/book ratio was inadequate to maintain the integrity of the book value of common stock as evidenced by the fact that the average market price of stock for PECO and the Barometer Group of Electric Companies and most utilities was less than book value. While there can be aberrations in a particular year, and the market price of stock may be either above or below book value, there has been an historically sustained market price of stock less than book value.

Accordingly, to use book value growth derived from a past period of time during which earnings were obviously insufficient to

maintain the integrity of presently invested capital, even measured at book cost, mandates the future will be a mirror image of the past, namely an inadequate rate of earnings insufficient to comport with the mandates of both Hope and Bluefield. Moreover, in the circumstance of PECO and many other electric companies, there has been a relatively recent significant upward movement in the achieved earnings book ratio which is expected to either sustain or increase in the future, given the fact that for some companies, such as PECO, while there has been an upward movement in the achieved earnings book ratio, the current earnings book ratios are less than intended by regulatory authorities. Thus, use of the past average earnings book ratio in a "b x r" calculation, as representative of the future, may understate the growth rate reflected in the price of stock currently; of course, the reverse could also be true. I do not believe it appropriate to use historic book value growth as a basis for forming a judgment about the future, except at best as a check, and then only regarding the past five years.

Q. IF YOU EMPLOYED A "b x r" CALCULATION AS THE METHOD TO ARRIVE AT THE GROWTH RATE REFLECTED IN THE PRESENT PRICE OF STOCK FOR PECO AND FOR EACH OF THE BAROMETER GROUP COMPANIES, HOW WOULD THAT GROWTH RATE COMPARE WITH THE GROWTH RATES YOU HAVE EMPLOYED IN YOUR DCF CALCULATION?

A. As can be derived from the information shown on Schedules 7 and 11, for the five years ended 1984 for PECO, the "b x r" derived growth rate would be 1.8% (five year average earnings/book ratio of 12.9% times the five year average retention ratio of 13.9%, which retention ratio is the complement of the five year average 86.1% dividend payout ratio). The 1.8% "b x r" derived growth rate is almost iden-

tical to the growth rate I have employed in my DCF calculation, which growth rate was the product of forecasts of earnings and dividend growth rates, as well as historic dividend growth rates, as I previously explained. If the spot data for 1985 was employed in the calculation, the PECO "b x r" growth rate would be 2.7%, or significantly higher than the 1.7% I employed in my DCF calculation (15.1% earnings/book ratio times 17.9% retention ratio).

With respect to the average "b x r" for the barometer group of four electric companies for the five years ended 1984, the growth rate would be 2.0%; and if the spot 1985 "b x r" calculation was employed, the growth rate would be 3.4%. The 2.0% and the 3.4% compare with the 2.9% I did employ based upon both forecasts and historic data, as previously explained.

B. Risk Spread Analysis

Q. PLEASE DESCRIBE YOUR RISK SPREAD ANALYSIS.

A. I believe the common equity cost rate for utilities is comprised of three elements. I call one element the bare rent for the use of utility capital, or a rate that ignores inflation and the risk of financial leverage. In other words, bare rent is the cost of capital without the business risk associated with exposing capital to an operating utility company endeavor and without regard to inflation and financial leverage. I am quite aware that one cannot precisely quantify a "bare rent rate," just as it is impossible to precisely quantify a "risk-free rate."

The second element is the protection required by investors for exposing their capital to the risk of inflation over the long term. The combination of the bare rent rate and the investor-expected rate of inflation, viewed over the longer term and currently reflected in

the cost of money, can be used to indicate the likely cost rate to attract utility long-term debt in the near-term future. Using the risk spread approach, it is not necessary to discover the investor-required rate of inflation protection. The required inflation protection is reflected in the cost of utility long-term debt.

The third element comprising a common equity cost rate is the increment above the combined bare rent and expected inflation rate. This is the increment investors require as a compensation for the risk of holding an equity security which has only a residual claim on earnings and assets.

The common equity risk component ("spread") above the long-term debt cost varies (as I will subsequently discuss in my testimony) depending upon the interest rate level.

Q. IS A PRECISE CALCULATION OF THE BARE RENT RATE OR THE INFLATION RATE CRUCIAL TO YOUR ANALYSIS?

A. No. Even though the various components may fluctuate, the yield on long-term public utility bonds captures all elements of cost related to inflation protection, bare rent rate or other elements required by investors. What is important is the prospective cost rate for long-term public utility debt which includes all component cost elements. I believe that 12.0% is a reasonable estimate of the prospective cost rate for typical new A rated public utility long-term debt and 12.5% for typical new Baa rated public utility bonds, as shown on Schedule 6. For clarification, it should be stated I believe PECO is not a typical company in terms of a Baa rating for its bonds. PECO's risk is higher and, it is quite possible its cost rate to attract new long-term debt could be higher than 12.5%. In short, while PECO's bonds are rated Baa, the market treats PECO as

having a greater risk as evidenced by the fact that when PECO last sold new long-term debt in December of 1984, the interest rate was 14.0% at a time when other electrics whose bonds were rated Baa sold long-term debt at a cost rate of about 13.5%.

Q. HAVE YOU ATTEMPTED TO QUANTIFY THE RISK SPREAD BETWEEN DEBT AND EQUITY FOR UTILITY COMPANIES OVER THE COURSE OF THE PAST FEW YEARS?

A. Yes, I have. The results of my studies indicate that when interest rates rise dramatically, the risk spread between debt and equity tends to narrow, but equity cost rates are still higher than debt cost rates. The narrowing of the risk spread occurs in part because the use of a DCF computation to develop the risk spread lags reality, particularly when only historical data are employed. The cost rate for debt reflects the instantaneous impact of any market change. If interest rates fall dramatically, the risk spread widens, assuming the DCF approach employed to develop the risk spread between debt and equity is consistent.

Q. WOULD YOU BRIEFLY DESCRIBE THE STUDIES YOU HAVE PERFORMED?

A. Yes. Page 1 of Schedule 16 provides the results of these studies. My study included 82 electric companies, the barometer group electric companies, and PECO.

The period of time studied was the years 1981 through 1984, inclusive. These periods of time were chosen because publication of Merrill Lynch's "Quantitative Analysis" did not begin until 1981. Since my study develops a risk spread between debt and equity by the technique of developing a cost rate for common equity capital using a DCF computation and since, for reasons previously explained, projections by more than one publication should be employed, 1981 is the first year that can be studied. The results of the study are

shown for two distinct periods, 1981-82 and 1983-84. Interest rates peaked in 1981-82 and moderated considerably in 1983-84. Thus, the risk spread for these two distinct periods reveals quite different risk spreads.

Q. IN THE PROCESS OF DEVELOPING A RISK SPREAD, OR THE DIFFERENCE BETWEEN THE MARKET RELATED COST OF LONG-TERM DEBT AND COMMON EQUITY, DID YOUR CALCULATIONS IN EACH OF THE YEARS AND PERIODS OF TIME YOU STUDIED PROCEED FROM THE CALCULATION OF THE YEARLY COST RATE FOR BOTH DEBT AND COMMON EQUITY?

A. No. I developed common equity cost rates monthly (using a DCF method which included projection of growth in earnings and dividends by both Value Line and Merrill Lynch and historical dividend growth rates) and compared those monthly common equity cost rates with the monthly yield on a long-term debt for each company as published in Standard & Poor's Bond Guide.

I believe it is important to develop a risk spread based on a company-specific long-term debt and a company-specific cost of equity.

I also believe it is important to develop risk spreads for many companies over many months to avoid the possibility of a distortion caused by an abnormality in a particular month or for a particular company.

Q. WHAT RISK SPREAD HAVE YOU ADOPTED FOR THE COMPANY AND THE BAROMETER GROUP OF SIMILAR RISK ELECTRIC COMPANIES?

A. By referring to page 1 of Schedule 16, it is shown that at the average interest rate level of 13.7% for PECO for the years 1983-84, the risk spread was 3.7 percentage points. At an interest rate level of 13.6% for the four electric company barometer group whose

bonds are rated Baa, the risk spread was 2.7%. For the large 82 company group, whose bond rating likely averages A, the risk spread was 3.2% when interest rates averaged 13.1% for 1983-84.

As I previously stated and explained, I believe the prospective long-term interest rate for PECO is 12.5%. These data, together with all of the risk spreads shown on page 1, Schedule 16, suggest the proper risk spread between long-term debt and common equity for PECO is 4.5% (or 0.8% higher than the 3.7% when interest rates were 1.2% higher). I have adopted a 4.0% risk spread for the barometer group for similar reasons, as explained in Note 6 on Schedule 2, page 2, of my Exhibit. It should be noted that analyses of data derived from widely publicized studies performed by Ibbotson and Sinquefield over long periods of time tend to confirm the results of my risk spread analysis specific to electric companies.

Q. WHAT IS THE COST OF COMMON EQUITY FOR PECO AND THE BAROMETER ELECTRIC COMPANY GROUP USING THE RISK SPREAD APPROACH?

A. When the prospective long-term interest rate for Baa bonds is 12.5%, a reasonable judgment with respect to the risk spread is 4.5% for PECO; and thus, the indicated cost of common equity is 17.0%. A similar calculation for the barometer group, but with a 4.0% risk spread, indicates a 16.5% common equity cost rate. Both the 17.0% PECO and the 16.5% barometer group risk spread derived common equity cost rate is before recognition of the impact on cost rate occasioned by issuance and selling expenses.

VIII. Common Equity Return Conclusion

Q. WHAT IS THE AVERAGE OF YOUR DCF AND RISK SPREAD COMPUTATIONS FOR PECO AND FOR THE BAROMETER ELECTRIC COMPANY GROUP INCLUDED IN YOUR STUDY BEFORE ANY RECOGNITION OF ISSUANCE AND SELLING EXPENSES?

A. As summarized on page 1 of Schedule 2, for PECO the average of the 16.7% DCF and the 17.0% risk spread analysis indicates a common equity cost rate of 16.9% for PECO.

An identical calculation with respect to the barometer electric company group with bonds rated Baa indicates a cost rate of 15.8%.

Q. IS THERE ANY EVIDENCE THAT YOUR OPINION THAT THE COST RATE FOR COMMON EQUITY CAPITAL FOR PECO IS HIGHER THAN THE COST RATE FOR COMMON EQUITY CAPITAL FOR THE BAROMETER GROUP OF OPERATING ELECTRIC COMPANIES WHOSE BONDS ARE RATED Baa INCLUDED IN YOUR STUDY IS UNIQUE?

A. No. The return on common equity found fair by the Pennsylvania Public Utility Commission is approximately 16.7% for PECO (weighted average for gas and electric service) or 16.75% for just electric service. The average return on common equity most recently authorized for each of the companies comprising the barometer group whose bonds are rated Baa is approximately 15.6%, or 1.1% lower than PECO. Current computations indicate the cost rate for PECO common equity is also 1.1% higher than the barometer group. At the outset of my testimony I enumerated reasons investors require a higher return for PECO compared to other electric companies, including new risks or uncertainties for PECO not present when the current authorized rates of return were established.

Q. WHAT COST RATE FOR COMMON EQUITY DO YOU BELIEVE IS APPROPRIATE FOR PECO TO GIVE RECOGNITION TO THE IMPACT OCCASIONED BY SELLING AND ISSUANCE EXPENSES, AS WELL AS THE NEED TO PROVIDE AN OPPORTUNITY FOR THE STOCK TO SELL SLIGHTLY ABOVE BOOK VALUE?

A. In my judgment, the proper opportunity cost rate is 17.4%. An achieved rate in that range would result in a market price at slightly above book value. I previously explained why I believe it

is appropriate to give recognition to issuance and selling expenses in the determination of the proper cost rate for common equity capital for PECO. The minimum recognition is 3%. Thus, if a 16.9% rate of return on common equity would result in a market price of stock on a sustained basis equal to book value, 103% of 16.9% indicates the need for a 17.4% rate so that when new common stock is sold, the net proceeds will at least equal book value.

Q. HAVE YOU PREPARED A SCHEDULE TO INDICATE THE LEVEL OF COVERAGE AT PRESENT RATES ON A GOING LEVEL OR PRO FORMA BASIS AND AT PROPOSED RATES IN REGARD TO THE IMPLICIT LEVEL OF BEFORE-INCOME TAX INTEREST COVERAGE AND THE RATE OF EARNINGS RELATED TO THE COMMON EQUITY PART OF THE COMPANY'S RATE BASE CLAIM IN THIS PROCEEDING?

A. Yes. That information is shown on page 1 of Schedule 17. Please note that at present rates on a pro forma basis, the before-income tax interest coverage is but 1.3 times relative to the debt portion of the Company's rate base and the indicated rate of earnings on the common equity part of the Company's rate base is negative. These calculations proceed from the premise that the rate base would be financed with the same mix of capital and at the composite cost rate for debt and preferred stock for June 30, 1986.

Please also observe that at proposed rates before-income tax interest coverage would be 3.6 times and the indicated rate of earnings on the common equity part of the company's rate base claim would be but 15.75%.

Q. DOES THE COMPANY'S FILING IN THIS PROCEEDING REFLECT A RATE OF EARNINGS EQUAL TO THAT WHICH YOU RECOMMEND AS APPROPRIATE AND FAIR?

A. Obviously not in light of my previous statement. The Company decided to minimize the impact of rate shock by the technique of

phasing in its proposed new electric service rates and by seeking an overall rate of return less than appropriate. In my judgment, a 15.75% opportunity rate with respect to the common equity part of the rate base is obviously less than what the marketplace believes is appropriate for PECO.

Further, it should also be noted that the 15.75% opportunity rate is a rate which reflects the impact of a rate of earnings on job development investment tax credit (JDITC) financed property. If there was no return allowed on JDITC property, the filing would indicate an opportunity to earn even less than the 15.75% rate developed on page 1 on Schedule 17.

In the past this Commission has improperly treated JDITC for rate making purposes by implicitly assuming there is, in fact, an interest component which reduces income taxes when, in fact, no interest expense exists with respect to JDITC financed property. An opportunity to experience a rate of return equal to the overall rate of return found fair by the regulatory agency treated as if it was entirely equity capital has been the indicated IRS standard with regard to JDITC financed property. If the standard is not changed, both stockholders and consumers of PECO face an uncertain risk as a result of the actions of this Commission. If that risk becomes a reality, customers of PECO could be required to pay a higher cost of capital as reflected in the price of service, given the market's response to the actions of this Commission and the implementation of the Internal Revenue Service with regard to the law.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Appendix A to

Direct Testimony

of

Joseph F. Brennan, President
Associated Utility Services, Inc.

Concerning

Fair Rate of Return

Education, Business and Regulatory Experience of Joseph F. Brennan

Education

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

Non-Utility Employment

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

Utility Employment

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

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

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

Consulting Work - Nature of Work

In late 1967, I established my own business as a utility financial consultant. Since that time, I have been engaged on a financial consulting basis by many utility companies and by governmental agencies. My engagements have included studies concerning primarily the subject of fair rate of return. I have also testified on the subject of an appropriate level of profit for a manufacturing company affiliate of a public utility company, the proper rate of return for use in power supply agreements, and I have testified as to the proper toll revenue settlement ratio between telephone companies on the "cost" method of the division of toll revenue and pole rental charges between regulated companies. I have designed financing programs for public utility companies (water, gas, telephone, and cable television), and I have arranged the private placement of long- and short-term debt as well as preferred

stock with institutional investors such as insurance companies and banks. In addition, I have rendered an opinion as to the valuation of utility property in testimony offered to a court-appointed panel on behalf of the United States Department of Justice in connection with the acquisition by Washington Metro of D. C. Transit, using the capitalization of income approach. I have also rendered opinions of the valuation of utility property using the capitalization of income approach in property tax matters in New Jersey and Connecticut, in municipal acquisition matters in New Jersey, and in testimony offered before a court in the Province of Quebec, Canada, in connection with the value of telephone utility property subject to in effect condemnation by the regulatory authorities in Quebec, Canada. I have offered testimony before the Securities and Exchange Commission involving divestiture under the Public Utility Holding Company Act of 1935. My studies and testimonies have been presented in proceedings involving electric, gas distribution, telephone, cable television, bus transportation, microwave, steam heating, maritime shipping, and independent operating water and sewer companies.

Expert Testimony Offered Before Regulatory Bodies

I have offered testimony primarily with respect to the subject of fair rate of return or utility financial matters before state regulatory bodies in Alabama, Arkansas, Connecticut, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Vermont, Virginia, Washington, and West Virginia. I have offered testimony before the Public Service Commission of the District of Columbia; Metropolitan Dade County (Miami), Florida; the Public Service Com-

mission of the Commonwealth of Puerto Rico; the Virgin Islands; the Federal Communications Commission; the Federal Energy Regulatory Commission and its predecessor, the Federal Power Commission; the Federal Maritime Commission; the Interstate Commerce Commission; the Securities and Exchange Commission; and the Canadian Radio and Television Commission. I have also offered testimony in Arkansas, California, Colorado, Connecticut, Florida, Oklahoma, Pennsylvania, Texas, and West Virginia, before city and town agencies involved in setting cable television rates and charges.

Employment by Regulatory Agencies or Municipalities

As a consultant employed by the Delaware Public Service Commission, I have testified in several Delmarva Power & Light Company rate cases, two Diamond State Telephone Company cases, and several other cases. Diamond State was a wholly-owned subsidiary of American Telephone & Telegraph Company. I have also testified on behalf of the Arizona Corporation Commission in connection with rate cases filed by Mountain States Telephone & Telegraph Company, another Bell System unit. I have testified on behalf of the Commonwealth of Puerto Rico as a rate of return witness before the Federal Maritime Commission involving North Atlantic shipping rates, and I have testified before that Commission on behalf of the Virgin Islands in a similar matter. In addition, I offered testimony before the Securities and Exchange Commission involving the divestiture of the gas properties of Delmarva Power & Light Company under the Public Utility Holding Company Act of 1935, on behalf of the Delaware Public Service Commission. My testimony was also submitted before the FPC on behalf of the Delaware Public Service Commission involving the rate of return to employ in a power supply agreement involving a multi-state electric operation and in a case involving wholesale

power rates.

I have also been employed by the Cities of Rochester, New York, and Baltimore, Maryland, involving bus transportation. I have also been employed by Washington Metro and the United States Department of Justice concerning the valuation of D.C. Transit. I was part of a team of persons to make a study of the cost of service and a load management plan for the Environmental Planning Agency of the State of Hawaii involving Hawaiian Electric Company.

I offered testimony in regard to class rate of return differential to be reflected in the cost of service by customer class. I have also co-authored a study on this subject on behalf of the Delaware Public Service Commission which was funded by the Department of Energy, I have testified on this subject on behalf of investor-owned electric companies in Arkansas and Texas, and on behalf of the City of New Orleans. I have also offered testimony before the Regulatory Control Authority of Connecticut regarding new factors for cost of service studies and tariff design, and I have offered testimony before this body as to a methodology to employ in connection with the regulation of cable television and the overall rate of return requirement.

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

Partial List of Clients Served

ELECTRIC

Appalachian Power Company
Arkansas Power and Light Company
Atlantic City Electric Company
Carolina Power & Light Company
Delmarva Power & Light Company
Duquesne Light Company
Fitchburg Gas & Electric Light Co.
Indiana & Michigan Electric Company
Iowa-Illinois Gas & Electric Company
Kentucky Power Company
Lockhart Power Company
Metropolitan Edison Company
Michigan Power Company
Monongahela Power Company
Nantahala Power & Light Company
Ohio Edison Company
Ohio Power Company
Ohio Valley Electric Company
Pennsylvania Electric Company
Pennsylvania Power & Light Company
Pennsylvania Power Company
Philadelphia Electric Company
The Potomac Edison Company
Potomac Electric Power Company
Tampa Electric Company
The Washington Water Power Company
West Penn Power Company
Western Massachusetts Electric Company

GAS

American Natural Gas Company
Bay State Gas Company
Columbia Gas of Maryland
Columbia Gas of Pennsylvania
Columbia Gas of West Virginia
Consolidated Gas Supply Corporation
Delmarva Power & Light Company
East Ohio Gas Company
Elizabethtown Gas Company
Equitable Gas Company
Honolulu Gas Company
Hope Gas, Inc.
Indiana Gas Company
Lone Star Gas Company
Michigan Power Company (Gas Div.)
North Penn Gas Company
Northern Utilities, Inc.
Oklahoma Natural Gas Company
Panhandle Eastern Pipeline Company
Pennsylvania Gas & Water Company
Peoples Natural Gas Company
Philadelphia Electric Company (Gas Div.)
T.W. Phillips Gas & Oil Company
Providence Gas Company
Public Service Co. of N. Carolina, Inc.
The Southern Connecticut Gas Company
Texas Eastern Transmission Corporation
Transwestern Pipeline Corporation
UGI Corporation
Virginia Electric & Power Co. (Gas Div.)
West Ohio Gas Company

WATER & SEWER

American Water Works Company
(over 30 subsidiaries)
Artesian Water Company
Atlantic City Sewerage Company
Barnstable Water Company
Bridgeport Hydraulic Company
Edgartown Water Company
Elizabethtown Water Company
Florida Water & Utilities Company
Hackensack Water Company
Kaanapali Water & Sewer Co.
Long Island Water Corporation
Middlesex Water Company
New Haven Water Company
Newtown Artesian Water Company
Pennichuck Water Works
Pennsylvania Gas & Water Company
Philadelphia Suburban Water Company
Roaring Creek Water Company
St. Louis County Water Company
Seymour Water Company
Spring Valley Water Company
Utilities and Industries Corporation
York Water Company

TELEPHONE

Bell Telephone Company of Pennsylvania
Chesapeake & Potomac Telephone Co.
Commonwealth Telephone Company
Illinois Consolidated Telephone Co.
Norfolk & Carolina Telephone Company
Puerto Rico Telephone Company
Rochester Telephone Corporation
Virgin Islands Telephone Company
And over 50 operating subsidiaries of:
ALLTEL Corporation
Central Telephone Company
Continental Telephone Corporation
GTE Corporation
United Telecom, Inc.

CATV

American Television
Communication Corporation
Bakersfield Cable Television
Cable Owners Association - California,
Connecticut, New England,
Pennsylvania, Rocky Mountain,
Vermont
Cablecom-General, Inc.
Canadian Cable Television
COMCAST Cable Communications, Inc.
Kern County Cable Television
LVO Cable, Inc.
National Cable Television Association
National Cable Television Owners
Association
San Juan Cablevision
Warner Cable Corporation

REGULATORY AND GOVERNMENTAL

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

Memberships, Publications and Appearances

Memberships have included the American Gas Association, the United States Telephone Association, the National Association of Water Companies, the National Cable Television Association, The National Society of Rate of Return Analysts and the New England Gas Association.

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

In May 1970, 1979, and 1984, I appeared before the Iowa State University Conference on Public Utility Valuation and the Rate Making Process at Ames, Iowa. I also addressed the Mid-America Regulatory Conference at Iowa State University at Des Moines in 1983. In addition, I appeared before two different Annual Conventions of the National Cable Television Association to discuss rate regulation of cable television. I have also appeared in a similar capacity before regional cable television conventions in Dallas, Texas; Augusta, Maine; New York, New York; Philadelphia, Pennsylvania; Lancaster, Pennsylvania; and San Diego, California. In 1973 and 1974, I was invited to appear at NARUC-sponsored seminars at the University of South Florida in St. Petersburg. My assigned subject was "Fair Rate of Return". During 1975, I appeared before the New Jersey Utilities Association and addressed the Annual

Meeting of the New York Independent Telephone Association at Cornell University. I addressed an American Bar Association Seminar in Washington in 1977 and in 1982 in San Francisco, California, on the subject of cost of money. I presented a paper to the NARUC Annual Convention in New Orleans on the subject of utility rate making. I also presented a paper in 1978 at The Greenbrier before the Great Lakes Section of NARUC. In May 1979, I presented a paper in Columbus, Ohio, before the 2nd Annual Convention of the National Association of Regulatory Attorneys. I also made a presentation before a seminar conducted by the New Mexico State University in October 1979 and in May 1982. In April 1983, I delivered a speech concerning "Organizations in Transition: Telecommunications" at a forum sponsored by Arizona State University's College of Business Administration Alumni Association. I have presented prepared remarks before the American Gas Association's Finance Committee at Seminars in 1982 and 1984. I made a presentation at a seminar regarding cost of capital co-sponsored by Temple University in Atlantic City, NJ, in 1983. I also presented remarks at the Edison Electric Institute's 1984 Financial Forum in Phoenix, Arizona.

Philadelphia Electric Company - Electric Operations A-1

INCOME AVAILABLE FOR RETURN

12 MONTHS ENDED JUNE 30, 1985

(Thousand $)

	Actual (B-9)	Adjustments (A-3)	Proforma Pres. Rates	Addl. Revs. (A-4)	Proforma Proposed Rates
Operating Revenue	2,455,964	(29,670)	2,426,294	664,781	3,091,075
Operating Expenses					
Operating & Maintenance Exp.	1,515,648	109,954	1,625,602	(201,855)	1,423,747
Depn. & Amort. (incl. salvage)	160,804	95,863	256,667		256,667
Provision for Taxes					
Taxes Other Than Inc.	190,253	(117,005)	73,258	13,295	86,553
Income Taxes	106,135	(250,451)	(144,316)	424,691	280,375
Provision for Deferred Taxes	74,712	95,860	170,572		170,572
Income Taxes Def.-Prior Yrs.	(38,756)	4,635	(34,121)		(34,121)
ITC Adjustment-(net)	50,803	(8,856)	41,947		41,947
Total Taxes	383,157	(275,817)	107,340	437,986	545,326
Loss on Disposition	(153)		(153)		(153)
Total Operating Expenses	2,059,456	(70,000)	1,989,456	236,131	2,225,587
Operating Income Avail. for Return	396,508	40,330	436,838	428,650	865,488
Original Cost Measure of Value(p. A-2)			7,014,234		7,014,234
Return on Original Cost			6.23		12.34

Philadelphia Electric Company - Electric Operations
MEASURES OF VALUE
AT JUNE 30, 1985
(Thousand $)

		Reference	Original Cost
Utility Plant in Service			
	Electric	C-2	8,605,971
	Allocated Common	C-2	113,067
	Total O.C. Plant in Service		8,719,038
Less:	Book Reserve on Plant in Service	C-2	1,620,086
			7,098,952
Plus:	Non-Revenue Producing CWIP	C-8	219
	Land Held for Future Use	C-9	8,504
	Materials and Supplies	C-10	93,451
	Nuclear Fuel in Reactor	C-11	82,252
	Cash Working Capital	C-12	105,608
	Total Additions		290,034
Less:	Accumulated Deferred Inc. Taxes		
	Accelerated Amortization	B-2	3,278
	Liberalized Depreciation	B-16	363,818
	Customer Deposits	B-2	7,247
	Customer Advances	B-2	409
	Total Deductions		374,752
Measures Of Value			7,014,234

Philadelphia Electric Company - Electric Operations

ADJUSTMENTS TO INCOME AVAILABLE FOR RETURN

12 Months Ended June 30, 1983

(Thousand $)

Test Year Adjustments	Section Page	Operating Revenues	Oper. Exp. Excl. Taxes	Taxes Other Than Income	State Share Income Taxes	Federal Share Income Taxes	Effect on Income for Return
Elimination of STAC Revenue and Taxes	D-1	(131,430)		(122,031)	(9,399)		0
Full Year Effect of Present Base Rates	D-2	87,344		1,747	5,972	36,628	42,997
Annualization for Growth and Customers	D-3	16,766	4,936	335	802	4,919	5,774
Elimination of Energy Cost Adjustment	D-4	31,893	29,126	1,408	53	325	381
Wage and Benefit Increases	D-5		30,692		(2,155)	(13,219)	(15,518)
Book Depn at Year End, including Salvage	D-6		86,979				(86,979)
Tax Depreciation and Amort. at Year End	D-7				(18,137)	(111,239)	129,376
Normalization of Tax Deferrals	D-8				0	96,804	(96,804)
Tax Savings on Proforma Interest	D-9				(13,562)	(83,180)	96,742
Nuclear and Steam Prod. O&M Exp. Adj.	D-10		6,727		(469)	(2,879)	(3,379)
Reduction in O&M exp. to Reflect Retire.	D-11		(13,095)		914	5,603	6,578
Miscellaneous Adjustments & Amortization	D-12		(12,957)		898	5,306	6,753
Elimination of Lansdale Revenue and Fuel	D-13	(36,779)	(8,732)		(1,957)	(12,001)	(14,089)
Full Year Effect of Incr. in FICA Tax	D-14			1,536	(107)	(657)	(772)
Decommissioning Cost Adjustment	D-15		8,884		(620)	(3,801)	(4,463)
Spent Fuel Disposal Cost Adjustment	D-16		624		(44)	(267)	(313)
Damaged Nuclear Fuel Assbly. Amort.	D-17		310		(22)	(132)	(156)
Full Year of Limerick O&M Expense	D-18	0	75,740		(5,284)	(32,410)	(38,046)
Non-Jurisdictional Rate of Return	D-19	3,136	(3,617)		471	2,890	3,392
ITC Annualization	D-20				0	(8,856)	8,856
Adjustment to Roll Fuel Out of Base Rate	D-21*	(205,975)	(201,855)	(4,120)			0
Total		(29,670)	205,817	(117,005)	(42,646)	(116,166)	40,330

*Not included in totals, reflected on p. A-4

Philadelphia Electric Company - Electric Operations A-4

EFFECTS ON INCOME FOR RETURN
OF SUPPLEMENT NO. 15
12 Months Ending June 30, 1985
(Thousand $)

	Increase in Base Rates		
	Base Rate Increase Before Fuel Roll-Out	Fuel Roll-out From Base $.007505/kwh (D-21)	Net Base Rate Increase
Increase in Revenue (A-5)	870,756	(205,975)	664,781
Less: 2% Gross Receipts Tax	17,415	(4,120)	13,295
Less: Fuel Rolled-out of Base		(201,855)	(201,855)
Increase in Income Before Taxes	853,341	0	853,341
Increase in Income Taxes @49.758%	424,691	0	424,691
Increase in Income for Return	428,650	0	428,650

Philadelphia Electric Company - Electric Operations
Kilowatt Hour Sales and Revenue by Tariff Subdivisions
Twelve Months Ended June 30, 1985
($1,000)

	mWh Sales Year Ended 6/30/85 (1)	Number of Customers 6/30/85 (2)	Total Book Rev (3)	Less: Book STAC (4)	Less: Book Energy Cost Rate Revenue (5)	Base Revenue (6)=(3)-(4)-(5)	Tariff 26 Full Year Effect of Increase(D-2) (7)	Total Proforma Base Rev. (8)=(7)+(6)
R	6,309,814	1,118,266	$713,186	$40,102	($7,036)	$680,120	$43,985	$724,105
RH	1,421,620	92,062	119,608	6,755	(2,031)	114,884	4,622	119,506
OP-Off Peak (WH)	418,313	104,832 (a)	28,238	1,598	(553)	27,193	1,140	28,333
POL	8,578	3,529 (a)	1,650	93	(11)	1,568	-	1,568
GS	3,529,957	120,711	365,755	20,600	(4,328)	349,483	5,952	355,435
PD(Incl Riders)	2,007,489	2,501	171,113	9,647	(2,340)	163,806	6,415	170,221
HT(Incl Riders)	12,683,464	2,353	861,056	48,273	(15,205)	827,988	20,120	848,108
EP-A	427,274	1	28,697	1,781	(536)	27,452	2,180	29,632
EP-S	263,490	2	20,166	1,138	(334)	19,362	763	20,125
SLP	100,872	2	14,374	805	(115)	13,684	846	14,530
SLS	60,823	522	17,984	1,004	(75)	17,055	1,163	18,218
TL	38,065	207	3,930	221	(53)	3,762	144	3,906
BLI	62	3	7	-	-	7	-	7
Trans Rent Rider	-	(a)	269	15	-	254	14	268
Total Elec.	27,269,821	1,336,630	$2,346,033	$132,032	($32,617)	$2,246,618	$87,344	$2,333,962
Other Elec. Operations	1,217,847	3	109,931	-	-	109,931	-	109,931
Total Elec.	28,487,668	1,336,633	$2,455,964	$132,032	($32,617)	$2,356,549	$87,344	$2,443,893
Plus: STAC In Excess of STAC Related Taxes (D-1)								602
Plus: Revenue from Growth Adjustment (D-3)								16,766
Plus: Interest on overcollections - Time of Use (D-4)								(1,324)
Plus: Revenues Associated with Sales to Jersey Central Power and Light & the Borough of Lansdale (D-13)								(36,779)
Plus: Non Jurisdictional Rates Adjustment (D-19)								3,136
Total Revenue								$2,426,294

(a) Duplicate customers not included in total.

Philadelphia Electric Company - Electric Operations
Kilowatt Hour Sales and Revenue by Tariff Subdivisions
Twelve Months Ended June 30, 1985
($1,000)

	Total Proforma Base Rev. (8)=(7)+(6)	Proposed Base Revenue Prior To Roll-Out (9)	Roll-out of .7505¢/kWh per D-21 (10)=(1)x .7505¢	Proposed Net Base Revenue Supp. No. 15 (11)=(9)+(10)	$ Increase (12)=(11)-(8)	% Increase (13)=(12)/(8)
R	$724,105	$986,112	($47,355)	$938,757	$214,652	29.6%
RH	119,506	161,128	(10,669)	150,459	30,953	25.9
OP-Off Peak (WH)	28,333	31,472	(3,139)	28,333	0	0
POL	1,568	1,632	(64)	1,568	0	0
GS	355,435	487,626	(26,492)	461,134	105,699	29.7
PD(Incl Riders)	170,221	235,754	(15,066)	220,688	50,467	29.6
HT(Incl Riders)	848,108	1,194,713	(95,189)	1,099,524	251,416	29.6
EP-A	29,632	36,614	(3,207)	33,407	3,775	12.7 (a)
EP-S	20,125	25,093	(1,977)	23,116	2,991	14.9
SLP	14,530	15,287	(757)	14,530	0	0
SLS	18,218	18,674	(456)	18,218	0	0
TL	3,906	4,192	(286)	3,906	0	0
BLI	7	10	(1)	9	2	28.6
Trans Rent Rider	268	346	-	346	78	29.1
Total Elec.	$2,333,962	$3,198,653	($204,658)	$2,993,995	$660,033	28.3%
Other Elec. Operations	109,931	109,931	-	109,931	-	-
Total Elec.	$2,443,893	$3,308,584	($204,658)	$3,103,926	$660,033	27.0%
Plus: STAC In Excess of STAC Related Taxes (D-1)	602	602	-	602	-	-
Plus: Revenue from Growth Adjustment (D-3)	16,766	22,831	(1,317)	21,514	4,748	28.3%
Plus: Interest on overcollections - Time of Use (D-4)	(1,324)	(1,324)	-	(1,324)	-	-
Plus: Revenues Associated with Sales to Jersey Central Power and Light & the Borough of Lansdale (D-13)	(36,779)	(36,779)	-	(36,779)	-	-
Plus: Non Jurisdictional Rates Adjustment (D-19)	3,136	3,136	-	3,136		
Total Revenue	$2,426,294	$3,297,050	($205,975)	$3,091,075	$664,781	27.4%

(a) Percentage shown is based on comparison of proposed increase and revenues associated with actual load characteristics reflected in the March 1985 contract agreement. Refer to the Company's proof of revenue calculations, Interrogatory response IV-C-1, for the details supporting this percentage.

Philadelphia Electric Company - Combined Operations
BALANCE SHEET
June 30, 1985
(Thousand $)

ASSETS AND OTHER DEBITS	COMPANY	SYSTEM
Utility Plant		
Electric	$4,771,915	$4,915,596
Gas	456,864	456,864
Steam	53,820	53,820
Common	131,573	131,573
Construction Work in Progress	4,470,950	4,471,375
Total Utility Plant	$9,885,122	$10,029,228
Less Provision for Depreciation	(1,748,661)	(1,798,509)
Net Utility Plant	$8,136,461	$8,230,719
Nuclear Fuel	222,134	222,134
Property Under Capital Leases Incl. Nuclear Fuel	341,007	341,007
Net Utility Plant, incl. Nuclear Fuel	$8,699,602	$8,793,860
Other Property and Investments		
Non-Utility Property	$13,152	$13,374
Investments in Subsidiary Companies	129,743	57,060
Decommissioning Escrow Funds	10,079	10,079
Other Investments	1,000	1,000
Total	$153,974	$81,513
Current and Accrued Assets		
Cash	$25,419	$25,416
Temporary Cash Investments	20,991	24,772
Escrow Deposits	16,561	16,561
Special Deposits and Working Funds	9,212	9,214
Accounts Receivable	349,264	345,781
Materials and Supplies	125,909	126,612
Prepayments	70,598	72,292
Deferred Fuel Expense	187,790	188,800
Compensated Absences	40,864	41,478
Total	$846,608	$850,926
Deferred Debits		
Unamortized Debt Expense	14,781	14,802
Extraordinary Property Losses	4,275	4,275
Clearing Accounts	404	802
Miscellaneous Deferred Debits	59,821	61,058
Unamortized Loss on Reacquired Debt	12	12
Accumulated Deferred Taxes	41,649	41,649
Total	$120,942	$122,598
TOTAL ASSETS AND OTHER DEBITS	$9,821,126	$9,848,897

Philadelphia Electric Company - Combined Operations
BALANCE SHEET
June 30, 1985
(Thousand $)

LIABILITIES AND OTHER CREDITS	COMPANY	SYSTEM
Proprietary Capital		
Common Capital Stock	$2,469,098	$2,469,098
Preferred Capital Stock	890,881	890,881
Premium on Preferred Stock	1,214	1,214
Other Paid in Capital	6,091	6,091
	$3,367,284	$3,367,284
Retained Earnings	564,804	564,804
Total	$3,932,088	$3,932,088
Long-Term Debt		
Bonds	$3,104,000	$3,119,350
Pollution Control Notes	273,175	273,175
Other Long-Term Debt	796,866	796,866
Unamortized Premium on Long-Term Debt	(17,981)	(18,021)
Total	$4,156,060	$4,171,370
Current and Accrued Liabilities		
Short-Term Debt	-	$5,000
Pollution Control Notes	-	-
Obligations Under Capital Lease - Current	75,848	75,846
Compensated Absences Payable	40,864	41,478
Current Maturities of Long-Term Debt	-	-
Accounts Payable	129,155	125,299
Customers' Deposits	7,427 (a)	7,511
Taxes Accrued	53,585	55,396
Interest Accrued	104,299	104,625
Dividends Declared	117,872	117,872
Miscellaneous Current & Accrued Liabilities	23,010	23,109
Deferred Income Taxes on Fuel	96,273	96,738
Total	$648,333	$652,874
Deferred Credits		
Customers' Advances for Construction	$774 (b)	$884
Accumulated Deferred Investment Tax Credits	340,320	342,413
Other Deferred Credits	59,391	59,456
Unamortized Gain on Reacquired Debt	9,040	12,061
Obligation Under Capital Leases	265,160	265,160
Accumulated Deferred Income Taxes		
Accelerated Amortization Property	3,278	3,278
Other Property	399,327	401,958
Other	7,355	7,355
Total	$1,084,645	$1,092,565
TOTAL LIABILITIES AND OTHER CREDITS	$9,821,126	$9,848,897

(a) Electric Portion = $7,247
(b) Electric Portion = $409

Philadelphia Electric Company - Electric Operations

ELECTRIC PLANT
AT JUNE 30, 1985
(Thousand $)

Electric Plant In Service		
Intangible Plant		
302.	Franchises and Consents	$163
Production Plant		
Steam Production Plant		
310.	Land and Land Rights	7,598
311.	Structures and Improvements	222,007
312.	Boiler Plant Equipment	588,162
314.	Turbogenerator Units	180,054
315.	Accessory Electric Equipment	106,034
316.	Miscellaneous Power Plant Equipment	12,895
	Total Steam Production Plant	$1,116,750
Nuclear Production		
320.	Land and Land Rights	357
321.	Structures and Improvements	307,048
322.	Reactor Plant Equipment	614,150
323.	Turbogenerator Units	224,960
324.	Accessory Electric Equipment	181,741
325.	Miscellaneous Power Plant Equipment	43,747
	Total Nuclear Production Plant	$1,372,003
Hydraulic Production		
330.	Land and Land Rights	1,421
331.	Structures and Improvements	14,484
332.	Reservoirs, Dams and Waterways	34,292
333.	Water Wheels, Turbines and Generators	21,971
334.	Accessory Electric Equipment	8,662
335.	Miscellaneous Power Plant Equipment	2,039
336.	Roads, Railroads and Bridges	998
	Total Hydraulic Production Plant	$83,867
Other Production Plant		
340.	Land and Land Rights	849
341.	Structures and Improvements	4,406
342.	Fuel Holders, Producers and Accessories	22,449
343.	Prime Movers	-
344.	Generators	90,905
345.	Accessory Electric Equipment	13,064
346.	Miscellaneous Power Plant Equipment	2,282
	Total Other Production Plant	$133,955
Total Production Plant		$2,706,575

Philadelphia Electric Company - Electric Operations

ELECTRIC PLANT
AT JUNE 30, 1985
(Thousand $)

Electric Plant In Service (Continued)

Transmission Plant		
350.	Land and Land Rights	$47,850
352.	Structures and Improvements	14,934
353.	Station Equipment	219,022
354.	Towers and Fixtures	183,834
355.	Poles and Fixtures	444
356.	Overhead Conductors and Devices	83,864
357.	Underground Conduit	2,521
358.	Underground Conductors and Devices	33,914
359.	Roads and Trails	1,730
	Total Transmission Plant	$588,113
Distribution Plant		
360.	Land and Land Rights	21,195
361.	Structures and Improvements	35,022
362.	Station Equipment	280,305
364.	Poles, Towers and Fixtures	131,562
365.	Overhead Conductors and Devices	197,119
366.	Underground Conduit	140,481
367.	Underground Conductors and Devices	248,347
368.	Line Transformers	152,904
369.	Services	100,516
370.	Meters	90,918
371.	Installations on Customers' Premises	278
373.	Street Lighting and Signal Systems	26,378
	Total Distribution Plant	$1,425,025
General Plant		
389.	Land and Land Rights	1,967
390.	Structures and Improvements	17,219
391.	Office Furniture & Equipment	3,160
393.	Stores Equipment	404
394.	Tools, Shop and Garage Equipment	4,974
395.	Laboratory Equipment	7,382
397.	Communication Equipment	1,830
398.	Miscellaneous Equipment	961
	Sub-Total	$37,897
399.	Other Tangible Property Antitrust Price Adjustment	(2,783)
	Total General Plant	$35,114
Total Electric Plant In Service (carried forward)		$4,754,990

Philadelphia Electric Company - Electric Operations

ELECTRIC PLANT
AT JUNE 30, 1985
(Thousand $)

Total Electric Plant In Service (brought forward)	$4,754,990
Construction Work in Progress	4,464,217
Plant Held for Future Use	
Land and Land Rights	16,905
Other Than Land and Land Rights	21
Total	$16,926
Total Electric Plant	$9,236,133

Philadelphia Electric Company - Electric Operations

COMMON UTILITY PLANT
AT JUNE 30, 1985
(Thousand $)

Intangible Plant		
301.	Organization	$677
General Plant		
389.	Land and Land Rights	2,393
390.	Structures and Improvements	84,710
391.	Office Furniture and Equipment	20,191
392.	Transportation Equipment	8,809
393.	Stores Equipment	1,830
394.	Tools, Shop and Garage Equipment	6,952
396.	Power Operated Equipment	1,422
397.	Communication Equipment	1,866
398.	Miscellaneous Equipment	2,335
	Total - General Plant	$130,508
Total Common Utility Plant in Service		$131,185
Construction Work in Progress		$2,513
Plant Held for Future Use (Land and Land Rights)		$388
Total Common Utility Plant		$134,086

Philadelphia Electric Company
BOOK ACCUMULATED PROVISION FOR DEPRECIATION
OF UTILITY PLANT IN SERVICE
INCLUDING DECOMMISSIONING EXPENSE
JUNE 30, 1985
(Thousand $)

Effective with the Commission Order at Docket R-842590 (January 25, 1985), the Company began to maintain book depreciation reserve information by detailed plant accounts for electric and common plant. The reserve by plant account for electric operations, including allocated common can be found in Exhibit AW-2.

Reserve for Depreciation - Electric	$1,555,274
Decommissioning Expense (D-15)	15,746
Total Electric Reserve	$1,571,020
Share of Common $47,182 x 86.188% (B-17)	40,665
Total	$1,611,685

Philadelphia Electric Company and Subsidiary Companies

12 MONTHS ENDING JUNE 30, 1985
CONSOLIDATED STATEMENT OF INCOME
(Thousand $)

Operating Revenue	
Electric	$2,473,625
Gas	447,469
Steam	74,490
Total Operating Revenue	$2,995,584
Operating Expenses	
Total Operation and Maintenance	1,916,219
Provision for Depreciation and Amortization	179,484
Provision for Taxes	
Federal Income Taxes	105,269
State and Local Income Taxes	36,741
Investment Tax Credit Adjustments-Net	52,407
Deferred Income Taxes	37,884
Taxes Other Than Income	217,899
Total Provision for Taxes	450,200
Gain or Loss	(153)
Total Operating Expenses	2,545,750
Operating Income	449,834
Other Income	
Allowance for Other Funds Used During Construction	152,838
Other Income and Deductions	(6,189)
Income Taxes	129,489
Total Other Income	276,138
Income Before Interest Charges	725,972
Interest Charges	
Interest on Long-Term Debt	421,199
Other Interest	28,305
Allowance for Borrowed Funds - Credit	(242,957)
Total Interest Charges	206,547
Net Income	519,425
Dividends on Preferred Stocks	87,633
Earnings Available for Common Stock	$431,792
Common Stock Outstanding	
Average	161,315
Earnings per average share (dollars)	$2.68

Philadelphia Electric Company - Electric Operations
STATEMENT OF ELECTRIC OPERATING INCOME
TWELVE MONTHS ENDED JUNE 30
(Thousand $)

		1983	1984	1985
OPERATING REVENUE				
	Sales of Electricity:			
440	Residential	691,272	788,995	861,032
442	Commercial & Industrial	1,196,892	1,243,821	1,399,574
444	Public Street and Highway Lighting	29,449	31,572	36,289
445	Other Sales to Public Authorities	-	-	-
446	Sales to Railroads and Railways	41,854	46,203	48,863
447	Sales for Resale	94,135	90,324	63,821
448	Interdepartmental Sales	3,996	4,163	4,266
	Sub-Total	$2,057,598	$2,205,078	$2,413,845
	Other Operating Revenues:			
450	Forfeited Discounts	7,867	8,037	9,176
451	Miscellaneous Service Revenues	2,025	2,088	2,232
454	Rent from Electric Property	7,640	10,876	10,574
455	Interdepartmental Rents	4,503	4,503	4,503
456	Other Electric Revenues	18,689	36,821	15,634
	Sub-Total	$40,724	$62,325	$42,119
	Total Electric Operating Revenues	$2,098,322	$2,267,403	$2,455,964
OPERATING EXPENSES				
401	Operation and Maintenance Expense:			
	Power Production	979,651	1,005,444	1,156,648
	Transmission	22,294	21,936	24,082
	Distribution	87,462	96,274	101,239
	Customer Accounts	63,814	68,474	74,975
	Customer Service & Information	6,283	7,629	8,871
	Sales	481	776	611
	Administrative and General Expense	117,760	128,077	149,222
	Total Operation and Maintenance Expense	$1,277,745	$1,328,610	$1,515,648
403	Depreciation Expense	129,382	159,054	161,743
405	Amortization of Other Electric Plant	(641)	(641)	(644)
407	Amortization of Property Losses	2,781	3,191	(295)
	Taxes			
408.1	Taxes Other Than Income Taxes	148,186	167,694	190,263
409.1	Income Taxes (a)	89,702	56,806	106,135
410.1	Provisions for Deferred Income Taxes	49,325	166,628	74,712
411.1	Inc. Taxes Deferred in Prior Yrs. - Credit	(3,494)	(4,093)	(38,756)
411.4	Investment Tax Credit Adjustments	48,862	(5,445)	50,803
	Total Taxes	$332,581	$381,590	$383,157
411.6&7	Gain from Disposition of Utility Plant	82	(226)	(153)
	Total Operating Expenses	$1,741,930	$1,871,578	$2,059,456
	OPERATING INCOME	$356,392	$395,825	$396,508

(a) Includes Paysop tax credit adjustment, see p. B-14

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
TWELVE MONTHS ENDED JUNE 30
(Thousand $)

I. POWER PRODUCTION EXPENSES

STEAM POWER GENERATION

		1983	1984	1985
OPERATION				
500	Operation Supervision & Engineering	$8,824	$11,949	$13,722
501	Fuel	291,506	400,051	365,774
502	Steam Expenses	12,712	26,887	32,456
504	Steam Transferred - Credit - Fuel	(47,780)	(52,327)	(46,305)
505	Electric Expenses	6,180	6,256	6,965
506	Miscellaneous Steam Power Expenses	10,959	11,572	13,294
507	Rents	46	2,839	10,375
	Total Operation	$282,447	$407,227	$396,281
MAINTENANCE				
510	Maintenance Supervision and Engineering	7,016	7,533	8,527
511	Maintenance of Structures	5,024	5,906	7,142
512	Maintenance of Boiler Plant	43,627	60,391	56,054
513	Maintenance of Electric Plant	14,317	12,773	16,964
514	Maintenance of Miscellaneous Steam Plant	2,951	2,664	3,078
	Total Maintenance	$72,935	$89,267	$91,765
	Total Power Production Expenses-Steam Power	$355,382	$496,494	$488,046

NUCLEAR POWER GENERATION

OPERATION				
517	Operation Supervision and Engineering	$7,497	$9,032	$11,048
518	Fuel - Nuclear	65,426 (a)	68,531 (a)	75,196 (a)
519	Coolants and Water	883	780	730
520	Steam Expenses	19,963	15,770	19,498
523	Electric Expenses	1,734	1,502	1,634
524	Miscellaneous Nuclear Power Expenses	33,534	31,837	44,723
525	Rents	71	232	116
	Total Operation	$129,108	$127,684	$152,945
MAINTENANCE				
528	Maintenance Supervision and Engineering	12,933	16,295	16,562
529	Maintenance of Structures	4,189	4,366	6,192
530	Maintenance of Reactor Plant Equipment	22,254	20,436	27,368
531	Maintenance of Electric Plant	15,800	10,406	11,637
532	Maintenance of Miscellaneous Nuclear Plant	4,080	3,899	6,714
	Total Maintenance	$59,256	$55,402	$68,473
	Total Power Production Expenses-Nuclear Power	$188,364	$183,086	$221,418

(a) Includes spent nuclear fuel disposal expense of:
1983 - 16,408
1984 - 19,021
1985 - 16,451

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
Twelve Months Ended June 30
(Thousand $)

	1983	1984	1985
HYDRAULIC POWER GENERATION			
OPERATION			
535 Operation Supervision and Engineering	$324	$371	$358
536 Water and Power	217	297	313
537 Hydraulic Expenses	846	826	786
538 Electric Expenses	218	231	217
539 Misc. Hydraulic Pwr Generation Expenses	284	314	417
540 Rents	1	-	-
Total Operation	$1,890	$2,039	$2,091
MAINTENANCE			
541 Maintenance Supervision and Engineering	372	465	552
542 Maintenance of Structures	178	150	115
543 Maintenance of Reservoirs, Dams & Waterways	340	239	147
544 Maintenance of Electric Plant	3,062	3,192	2,445
545 Maintenance of Miscellaneous Hydraulic Plant	165	204	536
Total Maintenance	$4,117	$4,250	$3,795
Total Pwr Prod. Expenses-Hydraulic Pwr	$6,007	$6,289	$5,886
INTERNAL COMBUSTION GENERATION			
OPERATION			
546 Operation Supervision and Engineering	990	1,056	1,020
547 Fuel	21,139	46,914	20,869
548 Generation Expenses	1,283	1,596	1,375
549 Misc. Other Power Generation Expenses	1,250	1,308	1,615
550 Rents	4,561	4,561	4,561
Total Operation	$29,223	$55,435	$29,440
MAINTENANCE			
551 Maintenance Supervision and Engineering	497	556	603
552 Maintenance of Structures	331	451	331
553 Maintenance of Generating and Electric Plant	3,841	5,858	4,586
554 Maintenance of Miscellaneous Other Power	78	74	113
Total Maintenance	$4,747	$6,939	$5,633
Total Internal Combustion	$33,970	$62,374	$35,073
OTHER POWER SUPPLY EXPENSES			
555 Purchased Power	429,859	468,904	451,553
556 System Control and Load Dispatching	4,304	4,565	4,923
557 Other Expenses	(38,235)(a)	(216,268)(a)	(50,251)(a)
Total Other Power Supply Expenses	$395,928	$257,201	$406,225
Total Power Production Expenses	$979,651	$1,005,444	$1,156,648

(a) Electric Fuel Deferral = 1983 - ($38,245)
1984 - ($216,284)
1985 - ($50,283)

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
Twelve Months Ended June 30
(Thousand $)

TRANSMISSION EXPENSES

		1983	1984	1985
OPERATION				
560	Operation Supervision and Engineering	$1,996	$1,976	2,159
561	Load Dispatching	1,013	1,138	1,334
562	Station Expenses	1,994	1,880	1,764
563	Overhead Line Expenses	191	183	219
564	Underground Line Expenses	230	193	209
566	Miscellaneous Transmission Expenses	1,158	1,085	1,845
567	Rents	7,042	6,736	6,822
	Total Operation	$13,624	$13,191	$14,352
MAINTENANCE				
568	Maintenance Supervision and Engineering	901	730	764
569	Maintenance of Structures	247	350	375
570	Maintenance of Station Equipment	4,353	4,898	4,870
571	Maintenance of Overhead Lines	2,464	2,220	2,547
572	Maintenance of Underground Lines	593	531	1,121
573	Maintenance of Miscellaneous Transmission Plant	112	16	53
	Total Maintenance	$8,670	$8,745	$9,730
	Total Transmission Expenses	$22,294	$21,936	$24,082

DISTRIBUTION EXPENSES

OPERATION				
580	Operation Supervision and Engineering	6,232	7,077	7,749
581	Load Dispatching	1,321	1,399	1,564
582	Station Expenses	4,912	5,179	5,169
583	Overhead Line Expenses	6,340	6,380	6,618
584	Underground Line Expenses	2,638	2,913	3,171
585	Street Lighting and Signal System Expenses	783	930	722
586	Meter Expenses	4,167	4,253	4,765
587	Customer Installation Expenses	4,495	4,432	4,424
588	Miscellaneous Distribution Expenses	8,927	10,163	11,274
589	Rents	2,614	4,225	3,961
	Total Operation	$42,429	$46,951	$49,417
MAINTENANCE				
590	Maintenance Supervision and Engineering	3,451	3,426	3,778
591	Maintenance of Structures	866	847	1,055
592	Maintenance of Station Equipment	6,370	7,284	8,117
593	Maintenance of Overhead Lines	21,672	23,470	23,091
594	Maintenance of Underground Lines	7,836	8,991	9,275
595	Maintenance of Line Transformers	1,247	1,579	1,738
596	Maintenance of Street Lighting and Signal System	1,302	1,093	1,142
597	Maintenance of Meters	1,482	1,550	2,188
598	Maintenance of Miscellaneous Distribution Plant	807	1,083	1,438
	Total Maintenance	$45,033	$49,323	$51,822
	Total Distribution Expenses	$87,462	$96,274	$101,239

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
Twelve Months Ended June 30
(Thousand $)

		1983	1984	1985
	IV CUSTOMER ACCOUNTS EXPENSES			
OPERATION				
901	Supervision	$1,988	$1,921	$2,272
902	Meter Reading Expenses	11,307	11,102	11,829
903	Customer Records	33,433	38,475	41,941
904	Uncollectible Accounts	15,962	15,941	18,123
905	Miscellaneous Customer Accounts Expenses	1,124	1,035	810
	Total Customer Accounts Expenses	$63,814	$68,474	$74,975
	V CUSTOMER SERVICE & INFORMATIONAL EXPENSES			
OPERATION				
907	Supervision	946	1,080	1,087
908	Customer Assistance Expenses	3,749	4,064	4,846
909	Informational & Instructional	1,104	1,833	2,534
910	Miscellaneous	484	652	404
	Total Cust. Serv. & Information Expenses	$6,283	$7,629	$8,871
	VI SALES EXPENSES			
OPERATION				
911	Supervision	111	125	124
912	Demonstrating and Selling Expenses	310	326	326
913	Advertising Expenses	38	234	155
916	Miscellaneous Sales Expenses	22	91	6
	Total Sales Expenses	$481	$776	$611
	VII ADMINISTRATIVE AND GENERAL EXPENSES			
OPERATION				
920	Administrative and General Salaries	24,418	28,701	31,704
921	Office Supplies and Expenses	13,368	12,877	15,752
923	Outside Services Employed	4,408	4,882	4,694
924	Property Insurance	8,624	8,804	8,805
925	Injuries and Damages	6,786	8,081	10,321
926	Employee Pensions and Benefits	43,723	46,474	49,010
928	Regulatory Commission Expenses	3,134	3,767	11,601
929	Duplicate Charges - Credit	(3,455)	(3,594)	(2,610)
930	General Advertising and Miscellaneous	15,938	16,938	18,353
	Sub-Total	$116,944	$126,930	$147,630
MAINTENANCE				
932	Maintenance of General Plant	816	1,147	(647)
935	Maintenance of General Plant	-	-	2,239
	Total Administrative and General Expenses	$117,760	$128,077	$149,222
	VIII TOTAL OPERATION AND MAINTENANCE EXP.	$1,277,745	$1,328,610	$1,515,648
	IX DEPRECIATION AND AMORTIZATION			
942	Depreciation	129,382 (a)	159,054 (a)	161,743 (a)
943	Amortization of Other Electric Plant	(641)	(641)	(644)
944	Amortization of Property Losses	2,781	3,191	(295)
	Total Depreciation and Amortization	$131,522	$161,604	$160,804

(a) Includes accruals for Nuclear Decommissioning of:
1983 - $3,260
1984 - $3,444
1985 - $3,832

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
Twelve Months Ended June 30
(Thousand $)

X TAXES	1983	1984	1985
TAXES OTHER THAN INCOME TAXES			
State and Local			
Capital Stock - Pennsylvania	$16,151	$18,402	$12,740
Capital Stock - New Jersey	245	212	149
Gross Receipts	87,728	94,594	105,213
Real Estate - Local	813	1,228	1,833
Real Estate - State	27,864	34,150	50,917
State Unemployment Compensation	472	1,795	1,032
Philadelphia Realty Occupancy	418	420	460
Other State and Local	1,120	1,760	1,191
Total State and Local	$134,811	$152,561	$173,535
Federal			
Telephone and Telegraph	16	46	51
Federal Unemployment Compensation	605	683	833
Federal Old Age Benefits	12,386	14,173	15,577
Other	368	231	267
Total Federal	$13,375	$15,133	$16,728
Total Taxes Other Than Income	$148,186	$167,694	$190,263
INCOME TAXES			
State - Pennsylvania	$28,317	$9,533	$29,253
State - Maryland	129	61	150
State - New Jersey	1,195	920	1,331
Federal	60,061	43,868	76,240
Total Income Taxes	$89,702	$54,382	$106,974
Provisions for Deferred Income Taxes	49,325	166,628	74,712
Income Taxes Deferred in Prior Years - Credit	(3,494)	(4,093)	(38,756)
Investment Tax Credit Adjustments*	48,862	(5,445)	50,803
Paysop Tax Credit Adjustment	-	2,424	(839)
TOTAL ALL TAXES	332,581	$381,590	$383,157
XI GAIN OR LOSS FROM DISPOSITION OF UTILITY PLANT -	82	(226)	(153)
XII TOTAL OPERATING EXPENSES (B-9)	$1,741,930	$1,871,578	$2,059,456

	1983	1984	1985
*Investment Tax Credit	$56,316	($205)	$59,210
Less: Amortization	(7,454)	(5,240)	(8,407)
	$48,862	($5,445)	$50,803

Philadelphia Electric Company - Electric Operations
FEDERAL INCOME TAX COMPUTATION
12 MONTHS ENDED JUNE 30, 1985
(Thousand $)

Operating Revenue			$2,455,964
Less: Operating Expenses			
Operating and Maintenance Expense		1,515,648	
Depreciation and Amortization		160,804	
State and Local Income Taxes		30,734	
Taxes Other Than Income		190,263	
Gain (Loss) on Utility Plant		(153)	
Balance			$558,668
Adjustments for Additional Items Affecting Taxable Income			
Deductions			
Gross Interest Charges Allocated to Electric Operations		193,578	
Additional Depreciation for Tax Purposes		23,258	
Contribution to Pension Fund Charged to Const.		8,161	
Taxes Charged to Construction		5,506	
Preferred Dividend Credit		787	
Amortization of Various Expenses Capitalized by R.A.		106	
Amort. Gain on Reacquired Bonds		1,056	
Spent Fuel - Pre 4/7/83		(9,608)	
Amortization of Easements & Clearing Rights of Way		523	
Net Leasing Expense - Salem 2		3,848	
Nuclear Fuel: Excess of Tax over Burn-up		1,649	
Deferred Fuel		50,283	
Schuylkill Abandon Losses		727	
Purta Recoverable		3,641	
Employee Benefits Capitalized		6,948	
Loss on ACRS Retirements		1,673	
Cost of Removal		2,742	
Gain on Sale of Real Estate		153	
Additions			
Reimburse Federal Income Taxes of SPCo		2,372	
Amortization of loss on Chester 5&6 and Barbadoes 6&7		432	
Nuclear Plant Decommissioning Expense		184	
Amortization of Turbine Lease Cancellation		10,027	
Purta Escrow		14,914	
R. R. Maint. Def. Rent Expense		31	
Amortization Pioneer Uravan Loss		189	
Miscellaneous Additions		741	
Sub-Total Net Deductions		$266,141	
Federal Income Tax Base - Operations			$292,527
Federal Income Tax @ 46%			134,562
Less: Paysop Credit			(839)
Investment Tax Credit (a)			59,209
Add: Prior Period Adjustment			48
Total Federal Income Tax Liability			$76,240

(a) There is $132,410 of ITC available to be carried forward to future years, exclusive of Trasop.

Philadelphia Electric Company - Electric Operations

ACCUMULATED DEFERRED TAXES
PER BALANCE SHEET (B-2) AS OF JUNE 30, 1985
(Thousand $)

The balance as of 6/30/85 in Accumulated Deferred Income Taxes including allocated common which amounts to $363,818 for electric operations as developed below, is deducted from the Company's investment in developing the rate base measures of value (A-2).

Combined Operations

	Total Per Balance Sheet (a)	Accumulated Deferred Taxes: Common Allocated (b)	Accumulated Deferred Taxes: Including Allocated Common
Electric	$357,112	$6,706	$363,818 (c)
Gas	31,709	1,006	32,715
Steam	2,725	69	2,794
Common	7,781	(7,781)	-
Total	$399,327		$399,327

a. Per B-2
b. Per B-17

Electric	86.188%
Gas	12.930
Steam	0.882
Total	100.000%

c. Includes capitalized pensions, taxes and fringe benefits of $33,148 for Electric

Philadelphia Electric Company - Combined Operations

DEVELOPMENT OF FACTORS FOR ALLOCATING COMMON
TO ELECTRIC, GAS, & STEAM OPERATIONS
June 30, 1986

	Plant in Service (1)	By Total Revenue (2)	By Total Customers (3)	Average (4)=(1)+(2)+(3) / 3
Basic Data	(Thousand $)	(Thousand $)	(Number)	
Electric	$8,726,738	$2,528,293	1,343,513	
Gas	485,912	450,484	309,770	
Steam	53,080	62,075	515	
Subtotal	$9,265,730	$3,040,852	1,653,798	
Common	142,487	-	-	
Total	$9,408,217	$3,040,852	1,653,798	
Allocation Factors				
Electric	94.183%	83.144%	81.238%	86.188%
Gas	5.244	14.814	18.731	12.930
Steam	0.573	2.042	0.031	0.882
Total	100.000%	100.000%	100.000%	100.000%

Philadelphia Electric Company - Combined Operations

CALCULATION OF EFFECTIVE INCOME TAX RATE

The effective income tax rate developed below combines into a single rate the effects of the federal income tax rate of 46% and the Pennsylvania income tax rate of 7.5%. The Pennsylvania income tax rate of 7.5% is the rate in effect prior to 1971 and is used here to reflect the level of Pennsylvania income taxes collectible through base rates. Changes in the Pennsylvania income tax rate since 1970 are collected through operation of the State Tax Adjustment Clause.

This effective income tax rate is intended for application to incremental changes in taxable income which result from 1) changes in revenue, less gross receipts taxes, associated with ratemaking adjustments, 2) changes in tax deductible expense associated with ratemaking adjustments and 3) additional revenues yielded by proposed rates. Because the effective income tax rate is applied to incremental changes in taxable income, it is independent of the overall average income tax rate experienced during the test year.

In 1970, prior to the establishment of the State Tax Adjustment Clause, Pennsylvania income taxes were deductible in determining both state and federal taxable incomes. Consequently, the effective state, federal or combined income tax rates must be determined either by a trial and error procedure or by use of algebraic formulae. The algebraic formulae used here act to determine an effective income tax rate to be applied to changes in taxable income before payment of both Pennsylvania and federal income taxes.

Pennsylvania Effective Income Tax, s:

$$s = 0.075 \times (\text{taxable income} - s)$$
$$s = (0.075 \times \text{taxable income}) - (0.075 \times s)$$
$$s + (0.075 \times s) = (0.075 \times \text{taxable income})$$
$$s \times (1 + 0.075) = (0.075 \times \text{taxable income})$$
$$s = \frac{0.075 \times \text{taxable income}}{1.075}$$
$$s = 0.06977 \times \text{taxable income}$$

Federal Effective Income Tax, f:

$$f = 0.46 \times (\text{taxable income} - s)$$
$$f = (0.46 \times \text{taxable income}) - (0.46 \times 0.06977 \times \text{taxable income})$$
$$f = (0.4600 - 0.03209) \times \text{taxable income}$$
$$f = 0.42791 \times \text{taxable income}$$

Summary:

	Rate		
	Statutory	Effective	Effective In % of Total
Pennsylvania	7.5%	6.977%	14.019%
Federal	46.0%	42.791	85.981
Total		49.768%	100.000%

PHILADELPHIA ELECTRIC COMPANY

DEBT CAPITAL
DEVELOPMENT OF WEIGHTED EFFECTIVE COST RATE
JUNE 30, 1985

($1,000)

Debt Issue	Nominal Date of Issue	Principal Amount Outstanding	Premium or (Discount)	Issue Expense	Net Proceeds Amount	Net Proceeds Per $100	Cost of Money Yield to Maturity	Cost of Money Weighted Interest
Mortgage Bonds & Debs								
12-1/2% due 2005	10/15/79	100,000	(883)	175	98,942	98.94	12.64%	12,640
10-1/2% due 2015	5/15/85	245,000	(6,039)	321	238,640	97.40	10.79%	25,436
4.85% S.F.deb due 1986	10/1/61	40,000	0	189	39,811	99.53	3.38%	1,352
4-5/8% due 1987	9/1/57	40,000	(284)	131	39,585	98.96	4.69%	1,876
3-3/4% due 1988	5/1/58	40,000	(360)	123	39,517	98.79	3.82%	1,528
4-3/8% due 1986	12/1/58	50,000	(315)	148	49,537	99.07	4.43%	2,215
5% due 1989	10/1/59	50,000	171	153	50,018	100.04	5.00%	2,500
4-1/2% due 1994	5/1/64	50,000	160	134	50,026	100.05	4.50%	2,250
6-1/8% due 1997	10/1/67	75,000	(270)	115	74,615	99.49	6.16%	4,620
6-1/2% due 1993	3/1/68	60,000	(401)	79	59,520	99.20	6.57%	3,942
9% S.F. due 1995	2/1/70	80,000	1,071	111	80,960	101.20	8.49%	6,792
7-3/4% S.F. due 2000	12/15/70	80,000	(772)	107	79,121	98.90	7.43%	5,944
8-1/4% due 1996	8/1/71	80,000	(369)	126	79,505	99.38	8.31%	6,648
7-3/8% due 2001	12/15/71	80,000	49	132	79,917	99.90	7.38%	5,904
7-1/2% due 1998	6/15/72	100,000	(14)	142	99,844	99.84	7.51%	7,510
7-1/2% due 1999	1/22/73	100,000	(384)	116	99,500	99.50	7.54%	7,540
8-1/2% due 2004	1/16/74	125,000	34	145	124,889	99.91	8.51%	10,638
11-5/8% due 2000	4/15/75	65,000	(423)	104	64,473	99.19	11.73%	7,625
11% due 2000	11/1/75	80,000	(700)	177	79,123	98.90	10.72%	8,576
9-1/8% due 2006	3/1/76	100,000	(875)	159	98,966	98.97	9.23%	9,230
9-5/8% due 2002	8/1/76	100,000	(875)	168	98,957	98.96	9.74%	9,740
8-5/8% due 2007	3/15/77	75,000	(670)	119	74,211	98.95	8.72%	6,540
6% due 2007	2/1/77	23,500	(429)	210	22,861	97.28	6.21%	1,459
8-5/8% due 2003	7/15/77	75,000	(429)	141	74,430	99.24	8.70%	6,525
9-1/8% due 2008	3/15/78	100,000	110	152	99,958	99.96	9.13%	9,130
13-3/4% due 1992	10/15/80	125,000	(904)	169	123,927	99.14	13.90%	17,375
14-3/4% due 2005	4/15/80	100,000	(687)	207	99,106	99.11	14.89%	14,890
14-1/8% due 1990	4/15/80	50,000	(334)	78	49,588	99.18	14.28%	7,140
17-5/8% due 2011	7/1/81	125,000	(2,344)	290	122,366	97.89	18.01%	22,513
18-3/4% due 2009	9/15/81	125,000	(1,089)	288	123,623	98.90	18.96%	23,700
15-1/4% due 1996	4/28/81	52,500	0	411	52,089	99.22	15.40%	8,085
15% due 1996	4/28/81	21,000	0	164	20,816	99.12	15.17%	3,186
18% due 2012	4/1/82	100,000	(1,875)	216	97,909	97.91	18.39%	18,390
15-3/8% due 2010	10/1/82	100,000	(701)	305	98,994	98.99	15.53%	15,530
13-3/8% due 2013	6/15/83	125,000	(2,301)	348	122,351	97.88	13.67%	17,088
14-1/2% SF Debs due 2009	2/15/84	150,000	(1,875)	308	147,817	98.54	14.74%	22,110
13.05% due 1994	11/26/84	20,000	0	148	19,852	99.26	13.19%	2,639
14% due 1988-94	12/1/84	80,000	0	369	79,631	99.54	14.10%	11,280
Subtotal		3,187,000	(25,007)	6,998	3,154,995			353,086

PHILADELPHIA ELECTRIC COMPANY

DEBT CAPITAL
DEVELOPMENT OF WEIGHTED EFFECTIVE COST RATE
JUNE 30, 1985

($1,000)

Debt Issue	Nominal Date of Issue	Principal Amount Outstanding	Premium or (Discount)	Issue Expense	Net Proceeds Amount	Net Proceeds Per $100	Cost of Money Yield to Maturity	Cost of Money Weighted Interest
Subtotal Carried Forward		3,187,000	(25,007)	6,998	3,154,995			353,086
Cumulative Reacquired S.F								
4.85% Debs due 1986	10/1/61	(19,200)	0	(91)	(19,109)	99.53	3.38%	(649)
7-3/4 S.F. due 2000	12/15/70	(19,200)	185	(26)	(18,989)	98.90	7.43%	(1,427)
9.0% S.F. due 1995	2/3/70	(20,548)	(275)	(29)	(20,794)	101.20	8.49%	(1,745)
11% S.F due 2000	11/1/75	(24,062)	211	(53)	(23,796)	98.90	10.72%	(2,579)
Bank Notes								
Citibank due 1988-89	5/28/79	75,000	0	0	75,000	100.00	9.50%(1)	7,125
Morgan due 1988	7/13/78	25,000	0	0	25,000	100.00	9.98%(2)	2,495
Chase due 1987	7/13/78	25,000	0	0	25,000	100.00	10.00%(3)	2,500
Chase due 1987	4/30/79	50,000	0	0	50,000	100.00	10.00%(3)	5,000
Chemical due 1987	5/28/79	50,000	0	0	50,000	100.00	9.98%(2)	4,990
Citibank due 1988	4/30/84	550,000	0	0	550,000	100.00	9.75%(4)	53,625
Unsecured Notes								
17% due 1986-87	6/29/82	20,000	0	36	19,964	99.82	17.06%	3,412
Pollution Control								
5.50% S.F. due 1997	10/1/72	33,000	0	581	32,419	98.24	5.02%	1,657
5.50% S.F due 1997	10/1/72	(8,515)	0	(150)	(8,365)	98.24	5.02%	(427)
13% due 2010	6/1/81	71,500	(1,793)	190	69,517	97.23	13.38%	9,567
11-1/2% due 2011	6/1/81	18,500	(2,236)	49	16,215	87.65	13.16%	2,435
Variable rate due 2012	12/1/82	60,000	(750)	174	59,076	98.46	5.87%	3,522
Variable rate due 2012	12/1/82	40,000	(500)	116	39,384	98.46	5.68%	2,272
Variable rate due 2013	9/1/83	50,000	(625)	177	49,198	98.40	5.69%	2,845
Variable rate due 2012	9/1/84	4,500	(56)	79	4,365	97.00	5.38%	242
Variable rate due 2012	9/1/84	4,200	(53)	63	4,084	97.24	5.38%	226
Other								
Note to Leon, Adeline & Nancy Naserio		98	0	0	98	100.00	6.00%	6
Note to Samuel & Catherine Edwards	7/19/77	102	0	0	102	100.00	8.00%	8
Note to Conrail		1,540	0	0	1,540	100.00	0.00%	0
Note to Ida Mack		31	0	0	31	100.00	12.00%	4
Note for Petro Pipeline		95	0	0	95	100.00	12.00%	11
Total		4,174,041	(30,899)	8,114	4,135,028			448,201
								10.74

(1) = Prime (Prime @ 9.50%) = 9.50%
(2) = 105% of Prime (Prime @ 9.50%) = 9.98%
(3) = 1/2 Of 1% over Prime (prime @ 9.50%) = 10.00%
(4) =Prime (Prime @ 9.50%) + .25% = 9.75%

A detailed discussion regarding the Embedded Cost of Debt is provided in the Direct Testimony of Joseph F Brennan

Philadelphia Electric Company
Preferred Stock
Development of Weighted Effective Cost Rate

June 30, 1985
($1,000)

Issue	Shares	Date of Issue	Principal Amount Outstanding	Total Discount and Expense or Net Premium	Net Proceeds Amount	Net Proceeds Per $100	Weighted Cost	Effective Cost Rate-%
4.400% Cumulative	226,499	Dec. 1941	$22,650	$0	$22,650	100.00%	$981	4.33%
4.400%	48,221	Mar. 1942	$4,822	$449	$5,271	109.31%	$209	4.33%
3.800% Cumulative	300,000	12/4/46	$30,000	($30)	$29,970	99.90%	$1,140	3.80%
4.300% Cumulative	150,000	2/5/48	$15,000	($468)	$14,532	96.88%	$666	4.44%
4.680% Cumulative	150,000	5/14/53	$15,000	($244)	$14,756	98.37%	$714	4.76%
7.000% Cumulative	400,000	2/4/69	$40,000	($646)	$39,354	98.39%	$2,884	7.21%
8.750% Cumulative	650,000	7/22/70	$65,000	($1,040)	$63,960	98.40%	$5,779	8.89%
7.850% Cumulative	500,000	3/10/71	$50,000	($801)	$49,199	98.40%	$3,990	7.98%
7.750% Cumulative	200,000	11/16/71	$20,000	($399)	$19,601	98.01%	$1,582	7.91%
7.600% Cumulative	750,000	4/20/72	$75,000	($1,106)	$73,894	98.53%	$5,940	7.92%
7.325% Cumulative	750,000	4/2/73	$75,000	($442)	$74,558	99.41%	$5,550	7.40%
9.500% Cumulative	750,000	4/18/74	$75,000	($1,093)	$73,907	98.54%	$7,230	9.64%
9.520% Cumulative	500,000	5/4/76	$50,000	($920)	$49,080	98.16%	$4,915	9.83%
8.750% Cumulative	500,000	5/1/78	$50,000	($225)	$49,775	99.55%	$4,405	8.81%
15.250% Cumulative	500,000	3/18/80	$50,000	($925)	$49,075	98.15%	$7,860	15.72%
10.000% Cumulative	220,000	3/18/80	$22,000	($131)	$21,869	99.40%	$2,215	10.07%
17.125% Cumulative	300,000	2/18/82	$30,000	($525)	$29,475	98.25%	$5,286	17.62%
12.800% Cumulative	750,000	2/9/83	$75,000	($3,443)	$71,557	95.41%	$10,065	13.42%
13.350% Cumulative	750,000	11/15/83	$75,000	($3,384)	$71,616	95.49%	$10,485	13.98%
14.625% Cumulative	500,000	3/28/84	$50,000	($888)	$49,112	98.22%	$7,445	14.89%
14.150% Cumulative	500,000	12/11/84	$50,000	($2,323)	$47,677	95.35%	$7,420	14.84%
(Redeemed)								
7.000% Cumulative	(104,000)		($10,400)	$168	($10,232)	98.38%	($750)	7.21%
7.325% Cumulative	(210,000)		($21,000)	$124	($20,876)	99.41%	($1,554)	7.40%
9.520% Cumulative	(105,310)		($10,531)	$194	($10,337)	98.16%	($1,035)	9.83%
8.750% Cumulative	(66,600)		($6,660)	$30	($6,630)	99.55%	($587)	8.81%
Total at 6/30/85			$890,881	($18,068)	$872,813		$92,835	10.42%

A detailed discussion regarding The Embedded Cost of Preferred Stock is contained in the Direct Testimony of Joseph F Brennan

Philadelphia Electric Company - Electric Operations

DESCRIPTION OF COMPANY'S CLAIMED
MEASURES OF VALUE

The Company's claimed rate base is its depreciated original cost of electric plant in service, including allocated common plant, and necessary other investment in used and useful plant facilities and working capital, at June 30, 1986. Depreciable plant and necessary investments in plant facilities and working capital as of June 30, 1985 are shown on page A-2.

Claimed utility plant in service has been taken from the Company's books of account which were originally approved by the Pennsylvania Public Utility Commission in the mid-1940's and have since been maintained in conformity with the Commission's regulations and with the Uniform System of Accounts for Class A electric companies prescribed by the Federal Energy Regulatory Commission (FERC). The Company's books of account were last audited by FERC in 1982, with the Pennsylvania Commission participating in that audit, and are audited on an annual basis by a firm of independent certified public accountants. In addition, the PaPUC audit staff recently completed an audit of the Company's property records through December 1983.

The Direct Testimony of Warren H. Smith, explains the detailed internal accounting procedures utilized by the Company to ensure that the original cost of utility plant is properly recorded in these accounts. A detailed description, together with extensive supporting documentation of the Company's depreciation reserve associated with plant in service at June 30, 1985 is presented in the Statement and Exhibits of Mr. Alfred Wroblewski. The several additions to Depreciated Utility Plant in Service as shown on page A-2 are discussed in Sections B and C of this Exhibit and are further described in the Statements and Exhibits of the Company witnesses there identified. The several deductions to Depreciated Utility Plant in Service are described by Thomas P. Hill, Jr.

Philadelphia Electric Company - Electric Operations
SUMMARY OF ORIGINAL COST OF PLANT
AND RELATED BOOK DEPRECIATION RESERVE
AS OF JUNE 30, 1985
($1,000's)

	Original Cost		
	Plant	Book Reserve	Net
Depreciable Plant in-Service (C-2f)	$8,489,025	$1,593,169	$6,895,856
Non-depreciable Plant in-Service (C-2g)	85,965	-	85,965
Total Electric Plant in Service per books	$8,574,990 (a)	$1,593,169 (a)	$6,981,821 (a)
Book Reserve Adjustments			
Additional AFUDC for Ratemaking (C-2h)	35,109	4,548	30,561
Excess Salvage (C-2h)	-	(14,284)	14,284
Adjusted plant and reserve	$8,610,099	$1,583,433	$7,026,666
Other Ratemaking Adjustments			
25 Cycle Equipment	(4,128)	(4,128)	-
Adjusted for Ratemaking	$8,605,971	$1,579,305	$7,026,666
Allocated Common from C-3	113,067	40,781	72,286
Total Electric and Allocated Common	$8,719,038	$1,620,086	$7,098,952

(a) Limerick 1 (C-2c)	$2,532,627	$25,839	$2,506,788
Limerick 100% Common Facilities			
Non-depreciable (AW-3, page 5)	7,349	-	7,349
Depreciable (C-2d)	1,271,675	12,731	1,258,944
Limerick Transmission (C-2d)	8,349	95	8,254
Sub-Total Limerick	$3,820,000	$38,665	$3,781,335
Other Electric Plant in-service (B-5)	4,754,990	1,554,504	3,200,486
Total Electric Plant in Service	$8,574,990	$1,593,169	$6,981,821

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
SUMMARY OF PRIMARY ACCOUNTS OF ORIGINAL COST
AND RELATED DEPRECIATION RESERVE FOR ELECTRIC PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

LOCATION ACCOUNT		ORIGINAL COST PLANT	RESERVE	NET
SCHUYKILL (1,3)	STEAM PRODUCTION			1992 = TERMINAL YEAR
1	3110 STRUCTURES AND IMPROVEMENTS	12269	8431	3838
1	3120 BOILER PLANT EQUIPMENT	43614	28800	14815
1	3140 TURBOGENERATOR UNITS	10405	7820	2585
1	3150 ACCESSORY ELECTRIC EQUIPMENT	10198	9444	755
1	3160 MISCELLANEOUS POWER PLANT EQUIP.	1180	774	406
STATION TOTAL		77666	55268	22398
CROMBY 2	STEAM PRODUCTION			1990 = TERMINAL YEAR
4	3110 STRUCTURES AND IMPROVEMENTS	7949	5882	2068
4	3120 BOILER PLANT EQUIPMENT	17612	15181	2431
4	3140 TURBOGENERATOR UNITS	10400	7863	2537
4	3150 ACCESSORY ELECTRIC EQUIPMENT	2699	2528	172
4	3160 MISCELLANEOUS POWER PLANT EQUIP.	678	640	39
STATION TOTAL		39339	32093	7246
EDDYSTONE 1 + 2	STEAM PRODUCTION			2010 = TERMINAL YEAR
6	3110 STRUCTURES AND IMPROVEMENTS	63148	25057	38091
6	3120 BOILER PLANT EQUIPMENT	186980	79329	107651
6	3140 TURBOGENERATOR UNITS	47574	26709	20865
6	3150 ACCESSORY ELECTRIC EQUIPMENT	27011	11161	15849
6	3160 MISCELLANEOUS POWER PLANT EQUIP.	2948	1673	1275
STATION TOTAL		327660	143929	183731
CROMBY 1	STEAM PRODUCTION			2004 = TERMINAL YEAR
7	3110 STRUCTURES AND IMPROVEMENTS	33713	10195	23518
7	3120 BOILER PLANT EQUIPMENT	61675	22827	38847
7	3140 TURBOGENERATOR UNITS	7736	5212	2524
7	3150 ACCESSORY ELECTRIC EQUIPMENT	5100	2836	2264
7	3160 MISCELLANEOUS POWER PLANT EQUIP.	632	457	175
STATION TOTAL		108855	41527	67328
DELAWARE (7,8)	STEAM PRODUCTION			1988 = TERMINAL YEAR
9	3110 STRUCTURES AND IMPROVEMENTS	16597	14055	2542
9	3120 BOILER PLANT EQUIPMENT	26244	18602	7642
9	3140 TURBOGENERATOR UNITS	11046	8747	2300
9	3150 ACCESSORY ELECTRIC EQUIPMENT	10044	8798	1246
9	3160 MISCELLANEOUS POWER PLANT EQUIP.	1799	1383	416
STATION TOTAL		65730	51585	14145
10	3110 STRUCTURES AND IMPROVEMENTS	14266	14097	169
10	3120 BOILER PLANT EQUIPMENT	16131	15184	947
10	3140 TURBOGENERATOR UNITS	7291	7024	267
10	3160 MISCELLANEOUS POWER PLANT EQUIP.	660	578	82
STATION TOTAL		41483	41177	305
12	3110 STRUCTURES AND IMPROVEMENTS	11919	10613	1306
12	3120 BOILER PLANT EQUIPMENT	21853	21281	572
12	3140 TURBOGENERATOR UNITS	9918	9668	250
STATION TOTAL		52123	50907	1216

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
SUMMARY OF PRIMARY ACCOUNTS OF ORIGINAL COST
AND RELATED DEPRECIATION RESERVE FOR ELECTRIC PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

LOCATION	ACCOUNT		ORIGINAL COST PLANT	RESERVE	NET	
CONEMAUGH (1,2)		STEAM PRODUCTION				2006 = TERMINAL YEAR
15	3110	STRUCTURES AND IMPROVEMENTS	5618	1843	3775	
15	3120	BOILER PLANT EQUIPMENT	33922	12941	20981	
15	3140	TURBOGENERATOR UNITS	15241	5826	9416	
15	3150	ACCESSORY ELECTRIC EQUIPMENT	4154	1349	2804	
15	3160	MISCELLANEOUS POWER PLANT EQUIP.	749	224	524	
STATION TOTAL			59684	22184	37501	
KEYSTONE (1,2)		STEAM PRODUCTION				2003 = TERMINAL YEAR
17	3110	STRUCTURES AND IMPROVEMENTS	8404	2550	5854	
17	3120	BOILER PLANT EQUIPMENT	32545	11359	21186	
17	3140	TURBOGENERATOR UNITS	12840	5509	7331	
17	3150	ACCESSORY ELECTRIC EQUIPMENT	3485	1294	2191	
17	3160	MISCELLANEOUS POWER PLANT EQUIP.	708	271	438	
STATION TOTAL			57983	20982	37000	
EDDYSTONE 3		STEAM PRODUCTION				2009 = TERMINAL YEAR
71	3110	STRUCTURES AND IMPROVEMENTS	45845	13680	32165	
71	3120	BOILER PLANT EQUIPMENT	95472	24585	70887	
71	3140	TURBOGENERATOR UNITS	27273	8909	18364	
71	3150	ACCESSORY ELECTRIC EQUIPMENT	22363	5560	16803	
71	3160	MISCELLANEOUS POWER PLANT EQUIP.	2567	677	1890	
STATION TOTAL			193520	53411	140110	
EDDYSTONE 4		STEAM PRODUCTION				2011 = TERMINAL YEAR
72	3120	BOILER PLANT EQUIPMENT	51072	13548	37524	
72	3140	TURBOGENERATOR UNITS	20328	5510	14817	
72	3150	ACCESSORY ELECTRIC EQUIPMENT	2132	1511	621	
STATION TOTAL			73531	20569	52962	
ALLIED CHEMICAL		STEAM PRODUCTION				1995 = TERMINAL YEAR
305	3110	STRUCTURES AND IMPROVEMENTS	130	14	115	
305	3150	ACCESSORY ELECTRIC EQUIPMENT	221	14	207	
STATION TOTAL			351	66	284	
ESSEX CHEMICAL		STEAM PRODUCTION				1995 = TERMINAL YEAR
306	3110	STRUCTURES AND IMPROVEMENTS	2150	407	1743	
STATION TOTAL			2150	407	1743	
TOOLS + WORK EQUIPMENT		STEAM PRODUCTION				0 = TERMINAL YEAR
372	3120	BOILER PLANT EQUIPMENT	1042	640	402	
STATION TOTAL			1042	640	402	
SAMAC		STEAM PRODUCTION				1992 = TERMINAL YEAR
503	3150	ACCESSORY ELECTRIC EQUIPMENT	8034	1641	6393	
STATION TOTAL			8034	1641	6393	

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
SUMMARY OF PRIMARY ACCOUNTS OF ORIGINAL COST
AND RELATED DEPRECIATION RESERVE FOR ELECTRIC PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

LOCATION	ACCOUNT		ORIGINAL COST PLANT	RESERVE	NET
TOTAL STEAM PRODUCTION					
999	3110	STRUCTURES AND IMPROVEMENTS	222007	106822	115185
999	3120	BOILER PLANT EQUIPMENT	588162	264316	323846
999	3140	TURBOGENERATOR UNITS	180054	98798	81256
999	3150	ACCESSORY ELECTRIC EQUIPMENT	106034	58760	47273
999	3160	MISCELLANEOUS POWER PLANT EQUIP.	12895	7690	5204
FUNCTIONAL TOTAL			1109151	536387	572764
SALEM 1		NUCLEAR PRODUCTION			2012 = TERMINAL YEAR
61	3210	STRUCTURES AND IMPROVEMENTS	49325	9880	39445
61	3220	REACTOR PLANT EQUIPMENT	142566	28771	113795
61	3230	TURBOGENERATOR UNITS	41929	6984	34944
61	3240	ACCESSORY ELECTRIC EQUIPMENT	54850	10998	43852
61	3250	MISCELLANEOUS POWER PLANT EQUIP.	7138	1747	5390
STATION TOTAL			295807	58380	237427
SALEM 2		NUCLEAR PRODUCTION			2016 = TERMINAL YEAR
62	3210	STRUCTURES AND IMPROVEMENTS	56397	5468	50930
62	3220	REACTOR PLANT EQUIPMENT	187151	20829	166322
62	3230	TURBOGENERATOR UNITS	60062	-4446	64509
62	3240	ACCESSORY ELECTRIC EQUIPMENT	67195	6643	60552
62	3250	MISCELLANEOUS POWER PLANT EQUIP.	10658	698	9959
STATION TOTAL			381463	29192	352271
SALEM CF		NUCLEAR PRODUCTION			2016 = TERMINAL YEAR
63	3210	STRUCTURES AND IMPROVEMENTS	98352	19925	78427
63	3220	REACTOR PLANT EQUIPMENT	40712	8797	31915
63	3230	TURBOGENERATOR UNITS	42647	8460	34187
63	3240	ACCESSORY ELECTRIC EQUIPMENT	21955	3605	18350
63	3250	MISCELLANEOUS POWER PLANT EQUIP.	7298	1470	5828
STATION TOTAL			210965	42257	168708
PEACH BOTTOM 2 + 3		NUCLEAR PRODUCTION			2009 = TERMINAL YEAR
66	3210	STRUCTURES AND IMPROVEMENTS	101461	30439	71022
66	3220	REACTOR PLANT EQUIPMENT	243720	43930	199790
66	3230	TURBOGENERATOR UNITS	80323	20122	60201
66	3240	ACCESSORY ELECTRIC EQUIPMENT	37740	11542	26199
66	3250	MISCELLANEOUS POWER PLANT EQUIP.	18602	3929	14673
STATION TOTAL			481847	109963	371884
LIMERICK # 1		NUCLEAR PRODUCTION			2023 = TERMINAL YEAR
91	3210	STRUCTURES AND IMPROVEMENTS	313744	3042	310702
91	3220	REACTOR PLANT EQUIPMENT	1488167	15156	1473011
91	3230	TURBOGENERATOR UNITS	251741	2826	248915
91	3240	ACCESSORY ELECTRIC EQUIPMENT	360902	3654	357248
91	3250	MISCELLANEOUS POWER PLANT EQUIP.	118073	1161	116912
STATION TOTAL			2532627	25839	2506788

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
SUMMARY OF PRIMARY ACCOUNTS OF ORIGINAL COST
AND RELATED DEPRECIATION RESERVE FOR ELECTRIC PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

LOCATION	ACCOUNT		ORIGINAL COST PLANT	RESERVE	NET
LIMERICK 100% COM		NUCLEAR PRODUCTION			2023 = TERMINAL YEAR
99	3210	STRUCTURES AND IMPROVEMENTS	469201	4554	434647
99	3220	REACTOR PLANT EQUIPMENT	491607	5009	486598
99	3230	TURBOGENERATOR UNITS	40966	459	40507
99	3240	ACCESSORY ELECTRIC EQUIPMENT	192787	1953	190834
99	3250	MISCELLANEOUS POWER PLANT EQUIP.	77114	756	76358
STATION TOTAL			1271675	12731	1258944
NUCLEAR TRAINING CENTER		NUCLEAR PRODUCTION			2015 = TERMINAL YEAR
385	3210	STRUCTURES AND IMPROVEMENTS	1512	218	1294
385	3250	MISCELLANEOUS POWER PLANT EQUIP.	52	4	48
STATION TOTAL			1563	222	1342
TOTAL NUCLEAR PRODUCTION					
999	3210	STRUCTURES AND IMPROVEMENTS	1089993	73525	1016467
999	3220	REACTOR PLANT EQUIPMENT	2593924	122492	2471431
999	3230	TURBOGENERATOR UNITS	517667	34405	483262
999	3240	ACCESSORY ELECTRIC EQUIPMENT	735430	38394	697035
999	3250	MISCELLANEOUS POWER PLANT EQUIP.	238934	9766	229168
FUNCTIONAL TOTAL			5175947	278583	4897364
MUDDY RUN (1,2,3,4,5,6,7,8)		HYDRAULIC PRODUCTION			0 = TERMINAL YEAR
19	3311	GENERATION	12061	2753	9308
19	3312	CONSERVATION OF FISH +WILDLIFE	128	26	102
19	3313	RECREATION	2295	1008	1287
19	3321	GENERATION	33428	5832	27596
19	3323	RECREATION	864	137	727
19	3330	WATER WHEELS, TURBINES, GENS.	21971	5492	16479
19	3340	ACCESSORY ELECTRIC EQUIPMENT	8662	2469	6193
19	3351	GENERATION	1873	711	1162
19	3353	RECREATION	166	43	123
19	3360	ROADS, RAILROADS AND BRIDGES	998	506	492
STATION TOTAL			82445	18978	63467
TOTAL OTHER PRODUCTION					
999	3410	STRUCTURES AND IMPROVEMENTS	4406	2751	1655
999	3420	FUEL HOLDERS,PRODUCERS,ACCESSORI	22449	8338	14111
999	3440	GENERATORS	90905	43522	47383
999	3450	ACCESSORY ELECTRIC EQUIPMENT	13064	5742	7322
999	3460	MISCELLANEOUS POWER PLANT EQUIP.	2282	673	1609
FUNCTIONAL TOTAL			133106	61026	72080
TOTAL TRANSMISSION PLANT					
601	3520	STRUCTURES AND IMPROVEMENTS	14934	4580	10354
601	3530	STATION EQUIPMENT	219022	79932	139089
601	3531	LIMERICK TRANSMISSION	8349	95	8254
601	3540	TOWERS AND FIXTURES	183834	47286	136548
601	3550	POLES AND FIXTURES	444	248	197
601	3560	OVERHEAD CONDUCTORS AND DEVICES	83864	25242	58622
601	3570	UNDERGROUND CONDUIT	2521	1599	922
601	3580	UNDERGROUND CONDUCTORS + DEVICES	33914	21669	12245

	3590 ROADS AND TRAILS		1730	725	1005
	FUNCTIONAL TOTAL		548613	181376	367237

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
SUMMARY OF PRIMARY ACCOUNTS OF ORIGINAL COST
AND RELATED DEPRECIATION RESERVE FOR ELECTRIC PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

LOCATION	ACCOUNT		ORIGINAL COST PLANT	RESERVE	NET
TOTAL DISTRIBUTION PLANT					
601	3610	STRUCTURES AND IMPROVEMENTS	35022	13216	21806
601	3620	STATION EQUIPMENT	280305	136220	144086
601	3640	POLES, TOWERS AND FIXTURES	131562	47215	84347
601	3650	OVERHEAD CONDUCTORS AND DEVICES	197119	76525	120594
601	3660	UNDERGROUND CONDUIT	140481	46320	94161
601	3670	UNDERGROUND CONDUCTORS + DEVICES	248347	74048	174300
601	3680	LINE TRANSFORMERS	152904	50439	102465
601	3691	AERIAL	32351	14766	17584
601	3692	UNDERGROUND	68169	14458	53710
601	3701	METERS	64452	15654	48798
601	3702	METER INSTALLATIONS	26466	6279	20187
601	3710	INSTAL. ON CUSTOMERS' PREMISES	278	190	88
601	3730	LUMINARIES	14833	5957	8877
601	3731	AERIAL CONDUCTORS	376	355	21
601	3732	UNDERGROUND CONDUCTORS	9163	1995	7168
601	3733	P O L CONDUCTORS	2005	891	1114
FUNCTIONAL TOTAL			1403833	504529	899304
TOTAL GENERAL PLANT					
601	3900	STRUCTURES AND IMPROVEMENTS	17219	7025	10194
601	3911	OFFICE MACHINES	81	3	78
601	3912	OFFICE FURNITURE AND EQUIPMENT	2115	82	2034
601	3913	COMPUTERS	964	85	879
601	3930	STORES EQUIPMENT	404	186	218
601	3940	TOOLS, SHOP AND GARAGE EQUIPMENT	4974	1870	3104
601	3951	TESTING DIVISION	6144	1625	4519
601	3952	METER DIVISION	712	277	435
601	3953	CHEMICAL LABORATORY	526	132	394
601	3970	COMMUNICATION EQUIPMENT	1830	370	1459
601	3980	MISCELLANEOUS EQUIPMENT	960	636	325
FUNCTIONAL TOTAL			35930	12291	23639
CLASS OF SERVICE			8489025	1593169	6895856

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC OPERATIONS
SUMMARY BY PRIMARY ACCOUNTS OF ORIGINAL COST
FOR ELECTRIC PLANT IN SERVICE AT 6/30/85
($1,000'S)

NON DEPRECIABLE ACCOUNTS

302. FRANCHISES & CONSENTS (INTANG.)	163
310. LAND & LAND RIGHTS(STEAM PROD.)	7598
320. LAND & LAND RIGHTS(NUCLER PROD.)	7706
330. LAND & LAND RIGHTS(HYDRAL PROD.)	1421
340. LAND & LAND RIGHTS(OTHER PROD.)	849
350. LAND & LAND RIGHTS(TRANSMISSION)	47850
360. LAND & LAND RIGHTS(DISTRIBUTION)	21195
389. LAND & LAND RIGHTS(GENERAL)	1967
399. OTHER INTAIGIBLE (GENERAL)	-2782
TOTAL NON-DEPRECIABLE	85965

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC RATEMAKING ADJUSTMENTS
SUMMARY OF PRIMARY ACCOUNTS OF ORIGINAL COST
AND RELATED DEPRECIATION RESERVE FOR ELECTRIC PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

LOCATION ACCOUNT		ORIGINAL COST PLANT	RESERVE	NET
ADDITIONAL AFUDC				
EDDYSTONE 4	ADDITIONAL AFUDC - STEAM PROD.			2011 = TERMINAL YEAR
72	63110 STRUCTURES AND IMPROVEMENTS	2608	722	1886
72	63120 BOILER PLANT EQUIPMENT	1249	347	902
72	63140 TURBOGENERATOR UNITS	530	147	383
72	63150 ACCESSORY ELECTRIC EQUIPMENT	220	60	160
72	63160 MISCELLANEOUS POWER PLANT EQUIP.	128	36	92
STATION TOTAL		4735	1312	3423
SALEM 2	ADDITIONAL AFUDC - NUCLEAR PROD.			2016 = TERMINAL YEAR
62	63210 STRUCTURES AND IMPROVEMENTS	13418	1294	12124
62	63220 REACTOR PLANT EQUIPMENT	5584	542	5042
62	63230 TURBOGENERATOR UNITS	5757	558	5199
62	63240 ACCESSORY ELECTRIC EQUIPMENT	2939	285	2654
62	63250 MISCELLANEOUS POWER PLANT EQUIP.	1208	118	1090
STATION TOTAL		28906	2797	26109
PEACH BOTTOM 2 + 3	ADDITIONAL AFUDC - NUCLEAR PROD.			2009 = TERMINAL YEAR
66	63210 STRUCTURES AND IMPROVEMENTS	1468	438	1030
STATION TOTAL		1468	438	1030
TOTAL ADDITIONAL AFUDC		35109	4548	30561
TOTAL EXCESS SALVAGE - DISTRIBUTION				
601	63640 POLES, TOWERS AND FIXTURES	0	-6635	6636
601	63650 OVERHEAD CONDUCTORS AND DEVICES	0	-7646	7647
FUNCTIONAL TOTAL		0	-14283	14284

Philadelphia Electric Company - Common
SUMMARY OF ORIGINAL COST
AND RELATED DEPRECIATION RESERVE
FOR COMMON PLANT IN SERVICE
AS OF JUNE 30, 1985
($1,000's)

	Original Cost		
	Plant	Book Reserve	Net
Common Plant in Service (C-3a)	$116,419	$39,974	$76,445
Transportation Plant in Service (C-3b)	11,697	7,342	4,355
Total Depreciable Common Plant	$128,116	$47,316	$80,800
Add:			
Non-Depreciable			
301. Organization (Intangible)(B-6)	677	-	677
389. Land & Land Rights (General)(B-6)	2,393	-	2,393
Total Non-Depreciable	3,070	-	3,070
Total Common Plant in Service (B-6)	$131,186	$47,316	$83,870
Total Common Plant in Service Allocated			
(Per B-17)			
Electric 86.188%	$113,067	$40,781	$72,286
Gas 12.930	16,962	6,118	10,844
Steam 0.882	1,157	417	740
Total 100.000%	$131,186	$47,316	$83,870

PHILADELPHIA ELECTRIC COMPANY - COMMON PLANT
SUMMARY OF PRIMARY ACCOUNTS OF ORIGINAL COST
AND RELATED DEPRECIATION RESERVE FOR ELECTRIC PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

LOCATION ACCOUNT		ORIGINAL COST		
		PLANT	RESERVE	NET
TOTAL GENERAL PLANT				
601	43900 STRUCTURES AND IMPROVEMENTS	84710	28939	55771
601	43911 OFFICE MACHINES	2976	1275	1701
601	43912 FURNITURE AND EQUIPMENT	8698	4168	4530
601	43913 COMPUTERS	8518	996	7522
601	43930 STORES EQUIPMENT	1830	418	1412
601	43941 CONSTRUCTION TOOLS	281	229	52
601	43942 TRANSMISSION AND DIST. TOOLS	4759	1847	2912
601	43944 TRANS. AND DIST. INSTRUMENTS	395	181	215
601	43962 CONSTRUCTION TOOLS	1	1	0
601	43963 TRANSMISSION AND DIST. TOOLS	51	51	0
601	43970 COMMUNICATION EQUIPMENT	1866	407	1459
601	43982 FIRE FIGHTING EQUIP. NOT DATED	494	456	38
601	43983 FIRE FIGHTING EQUIP. SPEC.DATED	1760	969	791
FUNCTIONAL TOTAL		81	39	42
		116419	39974	76444
CLASS OF SERVICE		116419	39974	76444

PHILADELPHIA ELECTRIC COMPANY - TRANSPORTATION
SUMMARY OF PRIMARY ACCOUNTS OF ORIGINAL COST
AND RELATED DEPRECIATION RESERVE FOR ELECTRIC PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

LOCATION	ACCOUNT		ORIGINAL COST PLANT	ORIGINAL COST RESERVE	ORIGINAL COST NET
TOTAL TRANSPORTATION					
601	53920	TRANSPORTATION EQUIPMENT	8809	5937	2872
601	53943	GARAGE EQUIPMENT	1517	283	1234
601	53961	VEHICLES	1371	1122	249
FUNCTIONAL TOTAL			11697	7342	4355
CLASS OF SERVICE			11697	7342	4355

Philadelphia Electric Company - Electric Operations
Description of Annual and Accrued Depreciation

The depreciation figures claimed in this filing are based on plant life estimates developed in the Company's 1985 Plant Life Study (Exhibit AW-1) for electric and common plant.

The 1985 Plant Life Study (1985 Study) is the Company's latest plant mortality study and updates the 1984 study which was filed in R-842590. The update, identified as Exhibit AW-1, includes the addition of one year of additional retirement experience for 1983. Production plant retirement dates are based on the latest Engineering Department estimates available at the time the study was made. This includes a 15-year life span extension for Cromby 1 and Eddystone 1 and 2 coal units. This life extension, to which the Company is now committed, reduces the claimed annual depreciation substantially.

Effective February 1, 1985, the Company switched its depreciation methodology for electric and common plant from the whole life method to the remaining life method for financial accounting purposes. The remaining life method is used in developing annual and accrued depreciation in this filing with the book reserve adjusted to a rate making basis consistent with the Commission's order at R-842590. The annual depreciation accrual, book reserve and rate making adjustments are developed in Exhibit AW-2 and Exhibit AW-3 and are summarized in Section C of this exhibit.

Experienced net salvage is calculated separately and averaged over a five-year period. The net negative salvage is not adjusted for third party payments as claimed by the Company in the past, pending a decision on the appeal of this issue in the Commonwealth Court.

The Company plans to depreciate Limerick Unit No. 1 and its common facilities under the remaining life method used for the other electric plant. The Limerick life span used for depreciation purposes is 39 years. This is based on a 40 year license which began with low power testing in late 1984. Allowing for one year of pre-commercial testing results in a 39 year life span for depreciation purposes.

Additional information regarding the annual and the accrued depreciation is contained in the Direct Testimony of A. Wroblewski.

Philadelphia Electric Company - Electric Operations

SUMMARY
Adjusted Book Remaining Life Accruals
for Plant-in-Service at June 30, 1985
$1,000's

	Plant	Book Reserve	Net	Remaining Life Annual Accrual
Total Per Books (a) (C-5f)	$8,574,990	$1,593,169	$6,981,821 (c)	$235,338
Book Reserve Adjustment				
Additional AFUDC (C-5g)	35,109	4,548	30,561	1,052
Excess Salvage (C-5g)	-	(14,284)	14,284	487
Adjusted Remaining Life Accrual	$8,610,099	$1,583,433	$7,026,666	$236,877
Other Ratemaking Adjustments				
25 Cycle Equipment	(4,128)	(4,128)	-	- (b)
Total for Ratemaking	$8,605,971	$1,579,305	$7,026,666	$236,877

(a) Limerick 1 (C-5c) $2,532,627 $25,839 $2,506,788 $68,656
Limerick 100% Common Facilities
Non-depreciable (AW-3, page 5) 7,349 - 7,349 -
Depreciable (C-5d) 1,271,675 12,731 1,258,944 33,824
Limerick Transmission (C-5d) 8,349 95 8,254 254
Sub-Total Limerick $3,820,000 $38,665 $3,781,335 $102,734
Other Electric (B-5) 4,754,990 1,554,504 3,200,486 132,604
Total Per Books $8,574,990 $1,593,169 $6,981,821 $235,338

(b) Fully depreciated, no adjustment required.
(c) Includes $85,965 of non-depreciable plant-in-service

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
DEPRECIATION ACCRUAL BY ACCOUNTS
FOR PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

DESIG.	ACCOUNT	NET PLANT BASE	LIFE SPAN RATE %	LIFE SPAN TERM DATE	LIFE SPAN INTERIM CURVE	AVERAGE AGE LIFE & CURVE	AVERAGE AGE RATE %	ANNUAL ACCRUAL
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - SCHUYKILL (1,3)					1992 = TERMINAL YEAR		
1	3110 STRUCTURES AND IMPROVEMENTS	3838	14.37	1992	90-R4			552
1	3120 BOILER PLANT EQUIPMENT	14815	14.50	1992	70-R2			2148
1	3140 TURBOGENERATOR UNITS	2585	14.55	1992	75-R2			376
1	3150 ACCESSORY ELECTRIC EQUIPMENT	755	14.55	1992	75-R2			110
1	3160 MISCELLANEOUS POWER PLANT EQUIP.	406	14.43	1992	80-R3			59
STATION TOTAL		22398	14.48					3244
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - CROMBY 2					1990 = TERMINAL YEAR		
4	3110 STRUCTURES AND IMPROVEMENTS	2068	20.03	1990	90-R4			414
4	3120 BOILER PLANT EQUIPMENT	2431	20.27	1990	70-R2			493
4	3140 TURBOGENERATOR UNITS	2537	20.20	1990	75-R2			512
4	3150 ACCESSORY ELECTRIC EQUIPMENT	172	20.23	1990	75-R2			35
4	3160 MISCELLANEOUS POWER PLANT EQUIP.	39	20.12	1990	80-R3			8
STATION TOTAL		7246	20.18					1462
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - EDDYSTONE 1 + 2					2010 = TERMINAL YEAR		
6	3110 STRUCTURES AND IMPROVEMENTS	38091	4.02	2010	90-R4			1531
6	3120 BOILER PLANT EQUIPMENT	107651	4.20	2010	70-R2			4520
6	3140 TURBOGENERATOR UNITS	20865	4.23	2010	75-R2			882
6	3150 ACCESSORY ELECTRIC EQUIPMENT	15849	4.16	2010	75-R2			660
6	3160 MISCELLANEOUS POWER PLANT EQUIP.	1275	4.11	2010	80-R3			52
STATION TOTAL		183731	4.16					7645
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - CROMBY 1					2004 = TERMINAL YEAR		
7	3110 STRUCTURES AND IMPROVEMENTS	23518	5.27	2004	90-R4			1240
7	3120 BOILER PLANT EQUIPMENT	38847	5.42	2004	70-R2			2105
7	3140 TURBOGENERATOR UNITS	2524	5.50	2004	75-R2			139
7	3150 ACCESSORY ELECTRIC EQUIPMENT	2264	5.43	2004	75-R2			123
7	3160 MISCELLANEOUS POWER PLANT EQUIP.	175	5.38	2004	80-R3			9
STATION TOTAL		67328	5.37					3616
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - DELAWARE (7,8)					1988 = TERMINAL YEAR		
9	3110 STRUCTURES AND IMPROVEMENTS	2542	33.49	1988	90-R4			851
9	3120 BOILER PLANT EQUIPMENT	7642	33.59	1988	70-R2			2567
9	3140 TURBOGENERATOR UNITS	2300	33.57	1988	75-R2			772
9	3150 ACCESSORY ELECTRIC EQUIPMENT	1246	33.64	1988	75-R2			419
9	3160 MISCELLANEOUS POWER PLANT EQUIP.	416	33.42	1988	80-R3			139
STATION TOTAL		14145	33.56					4748
10	3110 STRUCTURES AND IMPROVEMENTS	169	100.00	1985	90-R4			169
10	3120 BOILER PLANT EQUIPMENT	947	100.00	1985	70-R2			947
10	3140 TURBOGENERATOR UNITS	267	100.00	1985	75-R2			267
10	3160 MISCELLANEOUS POWER PLANT EQUIP.	82	100.00	1985	80-R3			82
STATION TOTAL		305	100.00					305
12	3110 STRUCTURES AND IMPROVEMENTS	1306	100.00	1985	90-R4			1306
12	3120 BOILER PLANT EQUIPMENT	572	100.00	1985	70-R2			572
12	3140 TURBOGENERATOR UNITS	250	100.00	1985	75-R2			250
STATION TOTAL		1216	100.00					1216

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
DEPRECIATION ACCRUAL BY ACCOUNTS
FOR PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

DESIG.	ACCOUNT	NET PLANT BASE	LIFE SPAN RATE %	LIFE SPAN TERM DATE	LIFE SPAN INTERIM CURVE	AVERAGE AGE LIFE & CURVE	AVERAGE AGE RATE %	ANNUAL ACCRUAL
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - CONEMAUGH (1,2)					2006 = TERMINAL YEAR		
15	3110 STRUCTURES AND IMPROVEMENTS	3775	4.77	2006	90-R4			180
15	3120 BOILER PLANT EQUIPMENT	20981	4.93	2006	70-R2			1035
15	3140 TURBOGENERATOR UNITS	9416	4.92	2006	75-R2			463
15	3150 ACCESSORY ELECTRIC EQUIPMENT	2804	4.91	2006	75-R2			138
15	3160 MISCELLANEOUS POWER PLANT EQUIP.	524	4.81	2006	80-R3			25
STATION TOTAL		37501	4.91					1841
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - KEYSTONE (1,2)					2003 = TERMINAL YEAR		
17	3110 STRUCTURES AND IMPROVEMENTS	5854	5.56	2003	90-R4			326
17	3120 BOILER PLANT EQUIPMENT	21186	5.74	2003	70-R2			1215
17	3140 TURBOGENERATOR UNITS	7331	5.71	2003	75-R2			419
17	3150 ACCESSORY ELECTRIC EQUIPMENT	2191	5.72	2003	75-R2			125
17	3160 MISCELLANEOUS POWER PLANT EQUIP.	438	5.61	2003	80-R3			25
STATION TOTAL		37000	5.70					2110
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - EDDYSTONE 3					2009 = TERMINAL YEAR		
71	3110 STRUCTURES AND IMPROVEMENTS	32165	4.17	2009	90-R4			1343
71	3120 BOILER PLANT EQUIPMENT	70887	4.33	2009	70-R2			3068
71	3140 TURBOGENERATOR UNITS	18364	4.31	2009	75-R2			792
71	3150 ACCESSORY ELECTRIC EQUIPMENT	16803	4.31	2009	75-R2			725
71	3160 MISCELLANEOUS POWER PLANT EQUIP.	1890	4.22	2009	80-R3			80
STATION TOTAL		140110	4.29					6008
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - EDDYSTONE 4					2011 = TERMINAL YEAR		
72	3120 BOILER PLANT EQUIPMENT	37524	4.00	2011	70-R2			1503
72	3140 TURBOGENERATOR UNITS	14817	3.99	2011	75-R2			591
72	3150 ACCESSORY ELECTRIC EQUIPMENT	621	3.99	2011	75-R2			25
STATION TOTAL		52962	4.00					2118
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - ALLIED CHEMICAL					1995 = TERMINAL YEAR		
305	3110 STRUCTURES AND IMPROVEMENTS	115	10.00	1995	90-R4			12
305	3150 ACCESSORY ELECTRIC EQUIPMENT	207	10.08	1995	75-R2			21
STATION TOTAL		284	10.05					29
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - ESSEX CHEMICAL					1995 = TERMINAL YEAR		
306	3110 STRUCTURES AND IMPROVEMENTS	1743	10.00	1995	90-R4			174
STATION TOTAL		1743	10.00					174
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - TOOLS + WORK EQUIPMENT					0 = TERMINAL YEAR		
372	3120 BOILER PLANT EQUIPMENT	402				30-S0	5.73	23
STATION TOTAL		402					5.73	23
STEAM PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - SAMAC					1992 = TERMINAL YEAR		
503	3150 ACCESSORY ELECTRIC EQUIPMENT	6393	14.99	1992	30-R2			958
STATION TOTAL		6393	14.99					958

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
DEPRECIATION ACCRUAL BY ACCOUNTS
FOR PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

DESIG.	ACCOUNT	NET PLANT BASE	LIFE SPAN RATE %	LIFE SPAN TERM DATE	LIFE SPAN INTERIM CURVE	AVERAGE AGE LIFE & CURVE	AVERAGE AGE RATE %	ANNUAL ACCRUAL
STEAM PRODUCTION	- TOTAL OF ALL STATIONS		- TOTAL			0 = TERMINAL YEAR		
999	3110 STRUCTURES AND IMPROVEMENTS	115185	0.0	0	0-			8099
999	3120 BOILER PLANT EQUIPMENT	323846	0.0	0	0-			20191
999	3140 TURBOGENERATOR UNITS	81256	0.0	0	0-			5463
999	3150 ACCESSORY ELECTRIC EQUIPMENT	47273	0.0	0	0-			1306
999	3160 MISCELLANEOUS POWER PLANT EQUIP.	5204	0.0	0	0-			438
FUNCTIONAL TOTAL		572764					6.20	35496
NUCLEAR PRODUCTION	- NUCLEAR POWER GENERATING STATNS	- SALEM 1				2012 = TERMINAL YEAR		
61	3210 STRUCTURES AND IMPROVEMENTS	39445	3.71	2012	90-R4			1463
61	3220 REACTOR PLANT EQUIPMENT	113795	3.85	2012	70-R2			4386
61	3230 TURBOGENERATOR UNITS	34944	4.14	2012	50-R1			1446
61	3240 ACCESSORY ELECTRIC EQUIPMENT	43852	3.84	2012	75-R2			1682
61	3250 MISCELLANEOUS POWER PLANT EQUIP.	5390	3.75	2012	80-R3			202
STATION TOTAL		237427	3.87					9179
NUCLEAR PRODUCTION	- NUCLEAR POWER GENERATING STATNS	- SALEM 2				2016 = TERMINAL YEAR		
62	3210 STRUCTURES AND IMPROVEMENTS	50930	3.23	2016	90-R4			1646
62	3220 REACTOR PLANT EQUIPMENT	166322	3.36	2016	70-R2			5596
62	3230 TURBOGENERATOR UNITS	64509	3.64	2016	50-R1			2347
62	3240 ACCESSORY ELECTRIC EQUIPMENT	60552	3.35	2016	75-R2			2028
62	3250 MISCELLANEOUS POWER PLANT EQUIP.	9959	3.27	2016	80-R3			325
STATION TOTAL		352271	3.39					11942
NUCLEAR PRODUCTION	- NUCLEAR POWER GENERATING STATNS	- SALEM CF				2016 = TERMINAL YEAR		
63	3210 STRUCTURES AND IMPROVEMENTS	78427	3.23	2016	90-R4			2537
63	3220 REACTOR PLANT EQUIPMENT	31915	3.39	2016	70-R2			1082
63	3230 TURBOGENERATOR UNITS	34187	3.68	2016	50-R1			1257
63	3240 ACCESSORY ELECTRIC EQUIPMENT	18350	3.36	2016	75-R2			617
63	3250 MISCELLANEOUS POWER PLANT EQUIP.	5828	3.28	2016	80-R3			191
STATION TOTAL		168708	3.37					5684
NUCLEAR PRODUCTION	- NUCLEAR POWER GENERATING STATNS	- PEACH BOTTOM 2 + 3				2009 = TERMINAL YEAR		
66	3210 STRUCTURES AND IMPROVEMENTS	71022	4.17	2009	90-R4			2965
66	3220 REACTOR PLANT EQUIPMENT	199790	4.32	2009	70-R2			8627
66	3230 TURBOGENERATOR UNITS	60201	4.63	2009	50-R1			2788
66	3240 ACCESSORY ELECTRIC EQUIPMENT	26199	4.31	2009	75-R2			1130
66	3250 MISCELLANEOUS POWER PLANT EQUIP.	14673	4.21	2009	80-R3			618
STATION TOTAL		371884	4.34					16128
NUCLEAR PRODUCTION	- NUCLEAR POWER GENERATING STATNS	- LIMERICK # 1				2023 = TERMINAL YEAR		
91	3210 STRUCTURES AND IMPROVEMENTS	310702	2.60	2023	90-R4			8089
91	3220 REACTOR PLANT EQUIPMENT	1473011	2.73	2023	70-R2			40274
91	3230 TURBOGENERATOR UNITS	248915	3.01	2023	50-R1			7496
91	3240 ACCESSORY ELECTRIC EQUIPMENT	357248	2.72	2023	75-R2			9713
91	3250 MISCELLANEOUS POWER PLANT EQUIP.	116912	2.64	2023	80-R3			3084
STATION TOTAL		2506788	2.74					68656

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
DEPRECIATION ACCRUAL BY ACCOUNTS
FOR PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

DESIG.	ACCOUNT	NET PLANT BASE	LIFE SPAN RATE %	LIFE SPAN TERM DATE	LIFE SPAN INTERIM CURVE	AVERAGE AGE LIFE & CURVE	AVERAGE AGE RATE %	ANNUAL ACCRUAL
NUCLEAR PRODUCTION	- NUCLEAR POWER GENERATING STATNS - LIMERICK 100% COM					2023 = TERMINAL YEAR		
99	3210 STRUCTURES AND IMPROVEMENTS	464647	2.60	2023	90-R4			12097
99	3220 REACTOR PLANT EQUIPMENT	486598	2.73	2023	70-R2			13304
99	3230 TURBOGENERATOR UNITS	40507	3.01	2023	50-R1			1220
99	3240 ACCESSORY ELECTRIC EQUIPMENT	190834	2.72	2023	75-R2			5188
99	3250 MISCELLANEOUS POWER PLANT EQUIP.	76358	2.64	2023	80-R3			2014
STATION TOTAL		1258944	2.69					33824
NUCLEAR PRODUCTION	- NUCLEAR POWER GENERATING STATNS - NUCLEAR TRAINING CENTER					2015 = TERMINAL YEAR		
385	3210 STRUCTURES AND IMPROVEMENTS	1294	3.34	2015	90-R4			43
385	3250 MISCELLANEOUS POWER PLANT EQUIP.	48	3.37	2015	80-R3			2
STATION TOTAL		1342	3.34					45
NUCLEAR PRODUCTION	- TOTAL OF ALL STATIONS - TOTAL					0 = TERMINAL YEAR		
999	3210 STRUCTURES AND IMPROVEMENTS	1016467	0.0	0	0-			28840
999	3220 REACTOR PLANT EQUIPMENT	2471431	0.0	0	0-			73269
999	3230 TURBOGENERATOR UNITS	483262	0.0	0	0-			16555
999	3240 ACCESSORY ELECTRIC EQUIPMENT	697035	0.0	0	0-			20357
999	3250 MISCELLANEOUS POWER PLANT EQUIP.	229168	0.0	0	0-			6437
FUNCTIONAL TOTAL		4897364					2.97	145458
HYDRAULIC PRODUCTION	- ELECTRIC STEAM GENERATING STATNS - MUDDY RUN (1,2,3,4,5,6,7,8)					0 = TERMINAL YEAR		
19	3311 GENERATION	9308				87-R1	1.35	126
19	3312 CONSERVATION OF FISH +WILDLIFE	102				87-R1	1.24	1
19	3313 RECREATION	1287				87-R1	1.32	17
19	3321 GENERATION	27596				100-R2	1.19	328
19	3323 RECREATION	727				100-R2	1.19	9
19	3330 WATER WHEELS, TURBINES, GENS.	16479				40-R2	3.79	624
19	3340 ACCESSORY ELECTRIC EQUIPMENT	6193				40-S2	3.82	237
19	3351 GENERATION	1162				50-R2	2.74	32
19	3353 RECREATION	123				50-R2	2.61	3
19	3360 ROADS, RAILROADS AND BRIDGES	492				60-R2	2.25	11
STATION TOTAL		63467					2.19	1387
OTHER PRODUCTION	- TOTAL OF ALL STATIONS - TOTAL					0 = TERMINAL YEAR		
999	3410 STRUCTURES AND IMPROVEMENTS	1655	0.0	0	0-			159
999	3420 FUEL HOLDERS,PRODUCERS,ACCESSORI	14111	0.0	0	0-			1078
999	3440 GENERATORS	47383	0.0	0	0-			4269
999	3450 ACCESSORY ELECTRIC EQUIPMENT	7322	0.0	0	0-			680
999	3460 MISCELLANEOUS POWER PLANT EQUIP.	1609	0.0	0	0-			120
FUNCTIONAL TOTAL		72080					8.75	6306
TRANSMISSION PLANT	- MISCELLANEOUS - 601					0 = TERMINAL YEAR		
601	3520 STRUCTURES AND IMPROVEMENTS	10354				50-R5	2.94	304
601	3530 STATION EQUIPMENT	139089				45-S2	3.08	4287
601	3531 LIMERICK TRANSMISSION	8254				45-S2	3.08	254
601	3540 TOWERS AND FIXTURES	136548				35-S3	4.23	5775
601	3550 POLES AND FIXTURES	197				25-S2	8.78	17
601	3560 OVERHEAD CONDUCTORS AND DEVICES	58622				45-S2	3.07	1798
601	3570 UNDERGROUND CONDUIT	922				50-R4	6.00	55
601	3580 UNDERGROUND CONDUCTORS + DEVICES	12245				40-R4	5.53	677
601	3590 ROADS AND TRAILS	1005				25-R5	8.93	90

FUNCTIONAL TOTAL	367237		3.61	13257

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC PLANT
DEPRECIATION ACCRUAL BY ACCOUNTS
FOR PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

DESIG.	ACCOUNT	NET PLANT BASE	LIFE SPAN RATE %	LIFE SPAN TERM DATE	LIFE SPAN INTERIM CURVE	AVERAGE AGE LIFE & CURVE	AVERAGE AGE RATE %	ANNUAL ACCRUAL
DISTRIBUTION PLANT	- MISCELLANEOUS		- 601					
						0 = TERMINAL YEAR		
601	3610 STRUCTURES AND IMPROVEMENTS	21806				40-R4	5.96	1299
601	3620 STATION EQUIPMENT	144086				40-R2	3.96	5705
601	3640 POLES, TOWERS AND FIXTURES	84347				40-R1	3.40	2869
601	3650 OVERHEAD CONDUCTORS AND DEVICES	120594				40-L1	3.41	4113
601	3660 UNDERGROUND CONDUIT	94161				50-R4	3.50	3291
601	3670 UNDERGROUND CONDUCTORS + DEVICES	174300				55-RA	2.16	3768
601	3680 LINE TRANSFORMERS	102465				35-L0	3.61	3699
601	3691 AERIAL	17584				28-R3	6.69	1071
601	3692 UNDERGROUND	53710				40-R1	3.00	1611
601	3701 METERS	48798				29-S1	5.52	2693
601	3702 METER INSTALLATIONS	20187				52-S6	2.62	528
601	3710 INSTAL. ON CUSTOMERS' PREMISES	88				30-O3	3.48	3
601	3730 LUMINARIES	8877				17-R1	9.58	851
601	3731 AERIAL CONDUCTORS	21				7-L0	71.27	15
601	3732 UNDERGROUND CONDUCTORS	7168				27-LA	4.69	336
601	3733 P O L CONDUCTORS	1114				12-SA	14.20	158
FUNCTIONAL TOTAL		899304					3.56	32010
GENERAL PLANT	- MISCELLANEOUS		- 601					
						0 = TERMINAL YEAR		
601	3900 STRUCTURES AND IMPROVEMENTS	10194				30-R4	7.05	719
601	3911 OFFICE MACHINES	78				10-L0	12.04	9
601	3912 OFFICE FURNITURE AND EQUIPMENT	2034				10-L0	11.67	237
601	3913 COMPUTERS	879				10-L0	11.03	97
601	3930 STORES EQUIPMENT	218				23-L2	10.29	22
601	3940 TOOLS, SHOP AND GARAGE EQUIPMENT	3104				45-R2	3.10	96
601	3951 TESTING DIVISION	4519				45-L1	2.76	125
601	3952 METER DIVISION	435				35-R2	4.18	18
601	3953 CHEMICAL LABORATORY	394				42-R3	3.16	12
601	3970 COMMUNICATION EQUIPMENT	1459				30-R3	4.12	60
601	3980 MISCELLANEOUS EQUIPMENT	325				23-S1	8.09	26
FUNCTIONAL TOTAL		23639					6.02	1423
CLASS OF SERVICE		6895856					3.41	235338

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC RATEMAKING ADJUSTMENTS
DEPRECIATION ACCRUAL BY ACCOUNTS
FOR PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

DESIG. ACCOUNT	NET PLANT BASE	LIFE SPAN RATE %	LIFE SPAN TERM DATE	LIFE SPAN INTERIM CURVE	AVERAGE AGE LIFE & CURVE	AVERAGE AGE RATE %	ANNUAL ACCRUAL
ADDITIONAL AFUDC - STEAM PROD. - ELECTRIC STEAM GENERATING STATNS - EDDYSTONE 4					2011 = TERMINAL YEAR		
72 63110 STRUCTURES AND IMPROVEMENTS	1886	3.86	2011	90-R4			73
72 63120 BOILER PLANT EQUIPMENT	902	4.00	2011	70-R2			36
72 63140 TURBOGENERATOR UNITS	383	3.99	2011	75-R2			15
72 63150 ACCESSORY ELECTRIC EQUIPMENT	160	3.99	2011	75-R2			6
72 63160 MISCELLANEOUS POWER PLANT EQUIP.	92	3.90	2011	80-R3			4
STATION TOTAL	3423	3.92					134
ADDITIONAL AFUDC - NUCLEAR PROD. - NUCLEAR POWER GENERATING STATNS - SALEM 2					2016 = TERMINAL YEAR		
62 63210 STRUCTURES AND IMPROVEMENTS	12124	3.23	2016	90-R4			392
62 63220 REACTOR PLANT EQUIPMENT	5042	3.36	2016	70-R2			170
62 63230 TURBOGENERATOR UNITS	5199	3.64	2016	50-R1			189
62 63240 ACCESSORY ELECTRIC EQUIPMENT	2654	3.35	2016	75-R2			89
62 63250 MISCELLANEOUS POWER PLANT EQUIP.	1090	3.27	2016	80-R3			36
STATION TOTAL	26109	3.35					875
ADDITIONAL AFUDC - NUCLEAR PROD. - NUCLEAR POWER GENERATING STATNS - PEACH BOTTOM 2 + 3					2009 = TERMINAL YEAR		
66 63210 STRUCTURES AND IMPROVEMENTS	1030	4.17	2009	90-R4			43
STATION TOTAL	1030	4.17					43
TOTAL ADDITIONAL AFUDC	30561					3.44	1052
EXCESS SALVAGE - DISTRIBUTION					0 = TERMINAL YEAR		
601 63640 POLES, TOWERS AND FIXTURES	6636				40-R1	3.40	226
601 63650 OVERHEAD CONDUCTORS AND DEVICES	7647				40-L1	3.41	261
FUNCTIONAL TOTAL	14284					3.41	487

Philadelphia Electric Company - Electric Operations

SUMMARY
Remaining Life Accruals for Common
Plant In Service at June 30, 1985
($1,000)

	Plant	Book Reserve	Net	Remaining Li Annual Accrua
Total Per Books (C-6a and C-6b)	$131,186	$47,316	$83,870 (a)	$5,892
Less Transportation Cleared to Operating Expense (C-6b)				
392 Transportation	$8,809	$5,937	$2,872	$714
394.3 Garage Equipment	1,517	283	1,234	52
396.1 Vehicles	1,371	1,122	249	93
Total Transportation	$11,697	$7,342	$4,355	859
Total Common Less Transportation (C-6a)	$119,489	$39,974	$79,515	$5,033
Allocation of Common Less Transportation				
Per B-17				
Electric 86.188%	$102,985	$34,453	$68,532	$4,338
Gas 12.930	15,450	5,169	10,281	651
Steam 0.882	1,054	352	702	44
100.000%	$119,489	$39,974	$79,515	$5,033

(a) includes $3,070 of non-depreciable plant-in-service

PHILADELPHIA ELECTRIC COMPANY - COMMON PLANT
DEPRECIATION ACCRUAL BY ACCOUNTS
FOR PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

DESIG. ACCOUNT		NET PLANT BASE	LIFE SPAN RATE %	LIFE SPAN TERM DATE	LIFE SPAN INTERIM CURVE	AVERAGE AGE LIFE & CURVE	AVERAGE AGE RATE %	ANNUAL ACCRUAL
GENERAL PLANT - MISCELLANEOUS			- 601			0 = TERMINAL YEAR		
601	43900 STRUCTURES AND IMPROVEMENTS	55771				30-L2	5.22	2909
601	43911 OFFICE MACHINES	1701				10-L0	14.15	241
601	43912 FURNITURE AND EQUIPMENT	4530				10-L0	14.63	663
601	43913 COMPUTERS	7522				10-L0	12.15	914
601	43930 STORES EQUIPMENT	1412				40-L2	3.02	43
601	43941 CONSTRUCTION TOOLS	52				30-S0	5.07	3
601	43942 TRANSMISSION AND DIST. TOOLS	2912				30-S0	4.51	131
601	43944 TRANS. AND DIST. INSTRUMENTS	215				30-S0	5.07	11
601	43962 CONSTRUCTION TOOLS	0				10-S1	100.00	0
601	43963 TRANSMISSION AND DIST. TOOLS	0				10-S1	100.00	0
601	43970 COMMUNICATION EQUIPMENT	1459				30-R3	3.85	56
601	43981 MISC. EQUIP. OTHER THAN FIRE FTG	38				20-L2	9.75	4
601	43982 FIRE FIGHTING EQUIP. NOT DATED	791				20-L2	7.14	56
601	43983 FIRE FIGHTING EQUIP. SPEC.DATED	42				20-L2	6.79	3
FUNCTIONAL TOTAL		76444					6.58	5033
CLASS OF SERVICE		76444					6.58	5033

PHILADELPHIA ELECTRIC COMPANY - TRANSPORTATION
DEPRECIATION ACCRUAL BY ACCOUNTS
FOR PLANT IN SERVICE AT 6/30/85
(THOUSANDS $)

DESIG. ACCOUNT	NET PLANT BASE	LIFE SPAN RATE %	LIFE SPAN TERM DATE	LIFE SPAN INTERIM CURVE	AVERAGE AGE LIFE & CURVE	AVERAGE AGE RATE %	ANNUAL ACCRUAL
TRANSPORTATION - MISCELLANEOUS							
601 53920 TRANSPORTATION EQUIPMENT	2872	- 601					
601 53943 GARAGE EQUIPMENT	1234					0 = TERMINAL YEAR	
601 53961 VEHICLES	249				11-L2	24.87	714
FUNCTIONAL TOTAL	4355				30-S0	4.20	52
					10-S1	37.28	93
						19.72	859
CLASS OF SERVICE	4355					19.72	859

Philadelphia Electric Company - Electric Operations
PRODUCTION PLANT
LIFE SPAN DATA

Station	Unit	Terminal Year
Steam Production		
Richmond #9		1985
Cromby #1		2004 (1)
Cromby #2		1990
Delaware		1988
Eddystone 1&2		2010 (1)
Schuylkill		1992
Southwark		1985
Keystone		2003
Conemaugh		2006
Eddystone #3		2009
Eddystone #4		2011
Other Production (Excl. Croydon)		
Southwark	3,4,5&6	1992
Eddystone	10,20,30,40	1994
Cromby	Diesel	1990
Delaware	Diesel	1988
Richmond	Diesel	1990
Southwark	Diesel	1985
Schuylkill	Diesel	1993
Delaware	9,10,11,&12	1994
Schuylkill	10	1994
Chester	7,8,9	1994
Keystone	Diesel	2003
Falls	1,2,&3	1995
Moser	1,2,&3	1995
Conemaugh	Diesel	2006
Richmond	81,91,92	1998
Portable Equipment		1996
Salem	C.T.	1996
Croydon		1999
Richmond		1985
Nuclear		
Peach Bottom 2 &3		2009 (3)
Salem #1		2012 (3)
Salem #2		2016 (3)
Limerick #1		2024 (2)

(1) The terminal dates for Cromby 1 and Eddystone 1 and 2 include a 15 year life extension over the terminal year used in the prior rate proceeding at R-842590.

(2) Based on a 40 year operating license issued in 1984. The life span for depreciation purposes is 39 years, allowing one year for pre-commercial testing.

(3) Life span for ratemaking purposes is 35 years from in-service date.

Philadelphia Electric Company

Non-Revenue Producing Construction Work In Progress
(Thousand $)

	C.A. Number	Exp. @ 6/30/85	Exp. to Complete	Total	Est. Orig. Cost. Ret.	In-Service Date	Classification
Non Revenue Producing CWIP							
Eddystone							
Install Fire Line Riser in Crusher House	405614	$24	$154	$178	-	12/85	Safety
Peach Bottom							
Provide Personnel Door Inside Railroad Door	408532	6	35	41	-	10/85	Safety
Total Non Revenue Producing CWIP		$30	$189	$219	-		
Net to A-2 ($219 - 0)				$219			

Additional information and discussion of this claim is contained in the Direct Testimony of R. W. Wright.

Philadelphia Electric Company - Electric Operations
Land Held for Future Use (Account 105)
As of June 30, 1985
(Thousand $)

Location of Property	Date Originally Included in Plant Accounts	Date Construction Expected to Start	Expected In Service Date	Balance
Production				
Bradshaw Reservoir & Water R/W	1979	Under Construction	1986	$2,498
Merrill Creek Reservoir	1981	1985 (a)	1987	4,770
Total Production				$7,268
Transmission				
Land for Future Substations and Lines				
500 kv Line, Limerick-Whitpain	1972	1987	1989	$371
Total Transmission				$371
Distribution				
Land for Future Substations				
Middletown Substation	1974	Under Construction	1986	$388
Morton Substation	1975	1988	1990	409
Land for Expansion of Present Substations				
Woodbourne Substation	1974	1987	1989	52
Land for Expansion of Service Building				
Dungan Service Building	1974	1992	1992	16
Total Distribution				$865
Total Land Held for Future Use				$8,504

(a) Date construction is expected to start is contingent on government approval to build structures.

Additional information and discussion of this claim is provided in the Direct Testimony of R. W. Wright.

Philadelphia Electric Company - Electric Operations
MATERIALS AND SUPPLIES
June 30, 1985
(Thousand $)

The adjustment to rate base for materials and supplies is shown below. Regarding electric fuel inventory, the quantities of fuel expressed in either tons of coal or barrels of oil represent design averages required to maintain an adequate fuel supply. The unit price for coal and oil represent inventory prices as of June 30, 1985. The Direct Testimony of J. J. Carroll provides additional discussion on the Company's fuel inventory claim. The Direct Testimony of R. W. Wright provides additional discussion of the Company's non-fuel materials and supplies.

Electric Fuel Inventory (J. J. Carroll)			
Coal			
Philadelphia Area	300,000 tons @ $46.62/ton	$13,986	
Keystone	121,000 tons @ $30.41/ton	3,680	
Conemaugh	119,000 tons @ $37.85/ton	4,504	
Total Coal Inventory			$22,170
Oil			
No. 6 1.0% Sulphur	95,000 bbls @ $26.31/bbl	$2,499	
0.5% Sulphur	390,000 bbls @ $27.29/bbl	10,643	
No. 2	300,000 bbls @ $34.08/bbl	10,224	
Total Oil Inventory			$23,366
Plant Materials and Supplies (R. W. Wright)			
Electric operating			
Total			$44,495
Tools and related equipment			
Electric			2,444
Stores Expense Undistributed			
Allocated portion $1,132 x 86.188% (a)			976
Total Electric Materials and Supplies			$93,451

(a) page B-17

Philadelphia Electric Company - Electric Operations

AVERAGE ELECTRIC M&S AND
TOOLS AND RELATED EQUIPMENT
Thirteen Months Ended 6/30/85
($1,000's)

	Electric Fuel Inventory			Electric Tools and	All Operations Stores Exp.
	Coal	Oil	M&S	Related Equip	Undistributed
Jun. 1984	24,109	37,764	45,770	2,609	407
Jul.	24,007	30,803	45,710	2,662	515
Aug.	25,596	29,676	45,342	2,695	803
Sep.	26,397	31,195	45,622	2,550	979
Oct.	27,665	25,345	45,044	2,548	1,269
Nov.	27,263	31,123	45,367	2,555	1,364
Dec.	27,084	35,415	44,488	2,435	1,406
Jan. 1985	28,066	28,220	45,217	2,419	1,416
Feb.	19,075	28,364	44,176	2,410	1,558
Mar.	20,332	28,483	43,738	2,354	1,411
Apr.	21,230	31,992	43,405	2,291	1,268
May	19,403	30,357	43,241	2,172	1,184
June	18,877	26,722	41,314	2,067	1,138
13 Month Total	$309,104	$395,459	$578,434	$31,767	$14,718
13 Month Average	$23,777	$30,420	$44,495	$2,444	$1,132
Applicable to Electric - %					86.188%
- $					$976

Philadelphia Electric Company - Electric Operations

ADDITIONAL CAPITAL REQUIREMENT
ASSOCIATED WITH NUCLEAR FUEL ASSEMBLIES IN REACTOR
($1,000)

The purpose of this adjustment is to reflect in the Company's rate base claim, the value of the Limerick Unit #1 nuclear fuel assemblies in the reactor. The claim is based on the average anticipated level of nuclear fuel in the reactor during the two year operating period March 1986 through March 1988. Additional information regarding this claim is contained in the Direct Testimony of Thomas P. Hill, Jr.

Description	Amount
Limerick #1 Nuclear Fuel Cost	$129,736
Avg. Accumulated Burnup (3/86-3/88)	47,484
Average Nuclear Fuel in-stock	$82,252

Limerick #1 Fuel in Reactor

	Total Cost	Accumulated Book Burn	Net Balance
March 1986	$110,002	$5,224	$104,778
April	110,002	9,571	100,431
May	110,002	14,405	95,597
June	110,002	18,494	91,508
July	110,002	22,558	87,444
August	110,002	26,557	83,445
September	110,002	30,767	79,235
October	110,002	34,880	75,122
November	110,002	38,572	71,430
December	110,002	42,474	67,528
January 1987	110,002	47,623	62,379
February	110,002	51,428	58,574
March	110,002	51,428	58,574
April	110,002	51,428	58,574
May	154,852*	51,428	103,424
June	154,852	54,655	100,197
July	154,852	58,258	96,594
August	154,852	61,462	93,390
September	154,852	64,940	89,912
October	154,852	67,893	86,959
November	154,852	70,516	84,336
December	154,852	73,161	81,691
January 1988	154,852	76,970	77,882
February	154,852	80,197	74,655
March	154,852	82,204	72,648
25 Month Avg.	$129,736	$47,484	$82,252

*Includes $44,850 for reload

Philadelphia Electric Company - Electric Operations C-12
Cash Working Capital
June 30, 1985
(Thousands $)

Additional information regarding this claim is provided in the Direct Testimony of R. W. Wright.

Operating and Maintenance Expense	(C-12a)	98,930	
Taxes	(C-12b)	33,960	
Interest Payments	(C-12c)	(37,202)	
Preferred Dividend Payment	(C-12d)	220	
Average Bank Balances	(Below)	9,700	(a)
Total (to A-2)		105,608	

(a) Average Monthly Bank Balances for the future test year are expected to be $11.3 million(II-B-5) of which 86.188%(p. B-17) or $9.7 million is allocated to Electric Operations

Philadelphia Electric Company
Cash Working Capital Required for
Operating and Maintenance Expense
June 30, 1985
(0000)

Average Lag in Receipt of Revenue	46 (a)
Average Lag in Payment of O&M Expenses	20 (b)
Average Lag in Days Between Receipt of Revenue and Payment of Expenses	26
Proforma Test Year O&M Expenses	1,388,991
Average Daily Expenses	3,805
Working Capital Requirement	98,930

a) Class of Service

	Dollars	Lag Days	Lag $
Residential	861,032	49	42,190,568
Small Comm.&Ind.	367,405	48	17,635,440
Large Comm.&Ind.	1,117,596	44	49,174,224
	2,346,033		109,000,232

46 Days

(b) Average Lag in Payment of Expenses

	Actual	Pro Forma Adjustments		Pro Forma Expenses	Lag Days	Lag Dollars
Payroll	252,857	28,680	(c)	281,537	11	3,096,907
Net Interchange	401,270	(209,268)	(d)	192,002	35	6,720,070
Nuclear Fuel	75,196			75,196	47	3,534,212
Coal	104,440			104,440	31	3,237,640
Coal Freight Bills	20,683			20,683	5	103,415
Oil	211,738			211,738	19	4,023,022
Benefits	22,102	6,049	(c)	28,151	2	56,302
Pensions	26,908	2,571	(c)	29,479	15	442,185
Other Invoices	311,535	41,479	(e)	353,014	15	5,295,210
A&G Expenses and Rents	92,751			92,751	15	1,391,265
Total O&M Expenses	1,519,480	(130,489)		1,388,991		27,900,228

Average Lag in Payment of Expenses 20

(c) D-5 30,892
D-18 6,408

(d) D-3 4,936
D-13 (8,732)
D-21 (201,855)
D-19 (3,617)
(209,268)

(e) D-10 6,727
D-11 (13,095)
D-12 (12,870)
D-15 8,884
D-16 624
D-18 69,332
B-13 (18,123) (uncollectible accounts)
41,479

Philadelphia Electric Company
Cash Working Capital Required For
Payment of Taxes
June 30, 1985
(Thousand $)

Average Lag in Receipt of Revenue	46	(a)
Average Lag in Payment of Taxes	22	(b)
Average Lag in Days Between The Receipt of Revenue and Payment of Taxes	24	
Proforma Test Year Taxes	516,595	
Average Daily Taxes	1,415	
Working Capital Requirement	33,960	

Note a) See C-12a

Note b) Average Lag in Payment of Taxes

	Actual	Pro Forma Adjustments		Pro Forma Taxes	Lag Days	Lag Dollars
Ad Valorum	65,639			65,639	26	1,706,614
Other Taxes Other Than Income	124,624	37,041	(c)	161,665	(31)	(5,011,615)
State Income Taxes	30,734	25,559	(d)	56,293	62	3,490,166
Federal Income Taxes	76,240	156,758	(d)	232,998	47	10,950,906
Total Taxes	297,237	219,358		516,595		11,136,071
Average Lag in Payment of Taxes						22

Note (c) Taxes Other Than Income

A-4(GRT @ 4.5%)	40,209
D-2(GRT @ 4.5%)	4,033
D-3(GRT @ 4.5%)	774
D-14	1,536
D-21(GRT @ 4.5%)	(9,511)
	37,041

Note (d) Income Taxes

	State	Federal
A-4	59,537	365,154
D-2	5,972	36,628
D-3	802	4,919
D-5	(2,155)	(13,219)
D-7	(18,137)	(111,239)
D-9	(13,562)	(83,180)
D-10	(469)	(2,879)
D-11	914	5,603
D-12	198	1,217
D-13	(1,957)	(12,001)
D-14	(107)	(657)
D-15	(620)	(3,801)
D-16	(44)	(267)
D-18	(5,284)	(32,410)
D-19	471	2,890
Total	25,559	156,758

Cash Working Capital
Interest Payment Offset
(Thousand $)

Consistent with the Commission Order at Docket R-842590, the Company is including in its cash working capital claim, the effect of the lag in the payment of interest.

Rate Base (A-2) @ 6/30/85	7,014,234
% Financed by Debt	51.50
Rate Base Financed by Debt	3,612,331
Cost of Debt per B-19a	10.74
Interest Allocated to Rate Base	387,964
Average Daily Interest	1062.9
Net Lag Days(a)	35
Decrease in Cash Working Capital	37,202

(a) From Exhibit TPH-2, page C-12c

Cash Working Capital
Preferred Dividend Payment Offset
(Thousand $)

Consistent with the Commission Order at Docket R-842590, the Company including in its cash working capital claim, the effect of the lag in the payment of preferred dividends.

Rate Base (A-2) @ 6/30/85	7,014,
% Financed by Preferred	11
Rate Base Financed by Preferred	771,
Cost of Preferred per B-20	10.
Dividends Allocated to Rate Base	80,3
Average Daily Dividends	220
Net Lag Days(a)	
Increase in Cash Working Capital	2

(a) See Exhibit TPH-2, page C-12d

Philadelphia Electric Company - Electric Operations
ELIMINATION OF STATE TAXES AND RELATED STAC REVENUE
12 Months Ending June 30, 1985
(Thousand $)

Certain State Taxes are recovered by the State Tax Adjustment Clause (STAC) in the Company's tariff. The following adjustment removes the effect of higher state taxes enacted since 1969 and removes related STAC revenues. Additional discussion of this adjustment is contained in the Direct Testimony of G. A. Sileo.

State Taxes to be Removed		
Realty	50,917 (a)	
Gross Receipts Tax	61,908 (b)	
Capital Stock Tax	9,206 (c)	
Corporate Net Income Tax	9,399 (d)	
Total		$131,430
Related STAC Revenue to be Removed		
Actual STAC	132,032	
Portion not removed	602	
Portion removed		$131,430
Effect on income available for return		$0

(a) Actual Realty Tax	
(b) Actual Gross Receipts Tax from B-14	105,213
Less: 4.5% GRT on STAC rev. of $132,032	5,941
Less: 4.5% GRT on ECR rev of ($32,617)	(1,468)
Remainder: 4.5% GRT on other revenue	$100,740
Portions of GRT related to 1970 tax rate increase	
Full GRT on STAC rev	$5,941
Excess GRT on other revenue: $100,740x(2.5% incr/4.5% total)	55,967
Total	$61,908
(c) Actual Capital Stock Tax (CST) (From B-14)	$12,740
Portion of CST related to 1970 tax rate increase	
$23,015 x (0.4% incr / 1.0% total)	9,206
(d) Actual Corporate Net Income Tax (CNI) from B-14	$29,253
Plus: CNI portion of deferred taxes A/C liberalized depreciation on plant	523
CNI portion of deferred taxes on deferred fuel expense	421
Total	$30,197
Portion of CNI related to pre-1970 tax rates	
Actual test year taxable income for CNI	$321,224
Less: STAC revenue	132,032
Less: Tax Preference Items	334
Plus: Realty Tax	50,917
Plus: STAC - related Gross Receipts Tax	61,908
Plus: STAC - related Capital Stock	9,206
Pre-1970 taxable income for CNI	$310,889
Pre-1970 CNI tax @ 6.977%	$21,691
Portion of CNI related to 1970 tax rate increase ($30,197 - 21,691)	$8,506
Portion of CNI to be removed = ($8,506 / (1-State Income Tax Rate)	$9,399

Philadelphia Electric Company - Electric Operations

FULL YEAR EFFECT OF PRESENT BASE RATES
12 Months Ending June 30, 1985
($1,000)

By Commission Order adopted January 25, 1985 in R-842590 the Company was granted a base rate increase in the amount of $149.6 million based on a future test year ending December 31, 1984. New rates became effective January 25, 1985. Developed below is the full year effect of Tariff #26, Supp. No. 11 base rates for the 12 months ending June 30, 1985. Refer to the Direct Testimony of R. W. Wright for a more detailed explanation of this adjustment.

	12 Months Ending June 30, 1985		
	Book Base Revenue (Actual) (1)	Pro Forma Supp.No.11 Base Rev. (2)	Additional Revenue From New Rates (3)=(2)-(1)
R	$680,120	$724,105	$43,985
RH	114,884	119,506	4,622
OP	27,193	28,333	1,140
POL	1,568	1,568	-
GS	349,483	355,435	5,952
PD	163,806	170,221	6,415
HT (Incl. Riders)	827,988	848,108	20,120
EP-A	27,452	29,632	2,180
EP-S	19,362	20,125	763
SLP	13,684	14,530	846
SLS	17,055	18,218	1,163
TL	3,762	3,906	144
BLI	7	7	-
TRR	254	268	14
Total	$2,246,618	$2,333,962	$87,344

Increase in Base Revenue	$87,344
Less: Gross Receipts Tax @ 2%	1,747
Increase in Taxable Income	$85,597
Income Taxes @ 49.768%	42,600
Increase in Income Available for Return	$42,997

Philadelphia Electric Company - Electric Operations

SUMMARY OF ANNUALIZATION OF REVENUES, EXPENSES & TAXES
FOR CUSTOMERS ADDED AND INCREASED USAGE
12 Months Ended June 30, 1985
(Thousand $)

The purpose of this adjustment is to annualize revenues, expenses, and taxes in order to reflect the level of customers and the year-end usage per customer. A description of the methodology used in this adjustment is provided in the Direct Testimony of T. P. Hill, Jr..

	Total
Increase in Base Revenue (D-3a)	$16,766
Less: Gross Receipts Tax @ 2.0%	335
Increase in Revenue After Gross Receipts Tax	$16,431
Less: Increase in Operating Expenses 175,176,307 kWh (a) x 2.8178¢/kWh (b)	4,936
Increase in Taxable Income	$11,495
Less: Income Taxes @ 49.768%	5,721
Increase in Income for Return	$5,774

(a) From D-3a

Increase in usage of existing customers	342,633,396 kWh
Increase (decrease) in usage from new customers	(167,457,089) kWh
	175,176,307 kWh

(b) Represents fuel expense included in base rates

Philadelphia Electric Company - Electric Operations

GROWTH IN USAGE OF EXISTING CUSTOMERS
AND ANNUALIZATION OF NEW CUSTOMER USAGE (a)
12 Months Ended June 30, 1985
(Thousand $)

	Residential	House Heating	Small Comm. & Industrial	Large Commercial & Industrial: 20 Largest Customers	Large Commercial & Industrial: All Other	Total
Growth In Usage of Existing Customers And Additional Revenue						
Annual Growth In kWh, 3-Yr. Average (D-3b)	27	(511)	1,027	(2,709,167)	122,831	
1/2 of Annual Growth In kWh	14	(256)	514	(1,354,584)	61,416	
No. of Custs. Beginning of Test Year (D-3b)	1,220,568	81,625	118,174	20	5,093	
Increase Usage	17,087,952	(20,896,000)	60,741,436	(27,091,680)	312,791,688	342,633,396
Revenue, cents per kWh (b)	10.20¢	8.08¢	9.75¢	6.18¢	7.07¢	
Increased Revenue, Thousand $	$1,743	($1,688)	$5,922	($1,674)	$22,114	$26,417
Annualization of New Customer Usage and Additional Revenue						
Customers Added During Year (D-3b)	2,530	10,437	2,537	0	(256)	
1/2 of Customers Added During Year	1,265	5,219	1,269	0	(128)	
Average Use Per Customer In kWh (D-3b)	5,502	16,315	29,584	-	2,321,150	
Increased Sales In kWh	6,960,030	85,147,985	37,542,096	-	(297,107,200)	(167,457,089)
Revenue, Cents per kWh (b)	10.20¢	8.08¢	9.75¢	-	7.07¢	
Increased Revenue, Thousand $	$710	$6,880	$3,660	-	($21,005)	($9,755)
Customer Charge - Annual	$54.00	$54.00	$94.22	-	$2,860	
Revenue from Customer Charge, Thousand $	$68	$282	$120	-	($366)	$104
Total Additional Revenue	$2,521	$5,474	$9,702	($1,674)	$743	$16,766

a. Residential is total of Rates R and OP. House Heating is Rate RH. Small Commercial and Industrial is total of Rate GS. Large Commercial and Industrial is total of Rates PD and HT.

b. Revenue in cents per kWh is the average unit base revenue at Tariff No. 26, Supplement No. 11 (excluding customer charge revenue).

Philadelphia Electric Company - Electric Operations

DEVELOPMENT OF AVERAGE ANNUAL GROWTH IN KWH PER CUSTOMER

	12 Months Ended June 1982	12 Months Ended June 1985	3-Yr. Avg.
Residential			
mWh Sales	6,601,163	6,728,127	
Number of Customers			
Beginning of Period	1,217,336	1,220,568	
End of Period	1,216,987	1,223,098	
Monthly Average	1,217,909	1,222,961	
kWh per Average Customer	5,420	5,502	
Growth in kWh per Average Customer		82	27
House Heating			
mWh Sales	1,183,649	1,421,620	
Number of Customers			
Beginning of Period	62,865	81,625	
End of Period	68,855	92,062	
Monthly Average	66,323	87,138	
kWh per Average Customer	17,847	16,315	
Growth in kWh per Average Customer		(1,532)	(511)
Small Commercial & Industrial			
mWh Sales	3,038,426	3,529,957	
Number of Customers (excl. OL)			
Beginning of Period	114,518	118,174	
End of Period	114,843	120,711	
Monthly Average	114,650	119,320	
kWh per Average Customer	26,502	29,584	
Growth in kWh per Average Customer		3,082	1,027

Philadelphia Electric Company - Electric Operations

DEVELOPMENT OF AVERAGE ANNUAL GROWTH IN KWH PER CUSTOMER

	12 Months Ended June 1982	12 Months Ended June 1985	3-Yr. Avg.
20 Largest Customers			
mWh Sales	3,936,197	3,773,647	
Number of Customers			
Beginning of Period	20	20	
End of Period	20	20	
Monthly Average	20	20	
kWh per Average Customer	196,809,850	188,682,350	
Growth in kWh per Average Cust.		(8,127,500)	(2,709,167)
Large Commercial & Industrial Other Than 20 Largest			
mWh Sales	11,067,653	11,608,070	
Number of Customers			
Beginning of Period	5,725	5,093	
End of Period	5,584	4,837	
Monthly Average	5,668	5,001	
kWh per Average Customer	1,952,656	2,321,150	
Growth in kWh per Average Customer		368,494	122,831

Philadelphia Electric Company - Electric Operations
ELIMINATION OF ENERGY COST RATE REVENUE AND
RELATED FUEL EXPENSE
12 MONTHS ENDED JUNE 30, 1985
(Thousand $)

During the test year ended June 30, 1985, the Energy Cost Rate was in effect and permitted recovery of energy costs in excess of that level included in base rates. Under the ECR, energy costs collected in base rates equalled 2.8178¢ per kilowatthour during the test year. This adjustment removes from test year revenues and expenses all energy costs above the base cost of 2.8178¢ per kilowatthour and all associated ECR revenues. Refer to the Direct Testimony of T. P. Hill, Jr. for a more detailed explanation of this adjustment.

ECR Revenue to be Removed		
Test Year ECR revenue Including GRT @ 4.5%	($31,293) (a)	
Revenue Over Base to be Removed		($31,293)
Fuel Expenses to be Removed		
Total Energy Cost Allocated to PECo (D-4a)	$786,045	
Less: Fuel Expense Deferred 12 Months Ended 6/30/85 (D-4a)	50,283	
Net Fuel and Interchange Expense	$735,762	
Less: Fuel expense recovered in base rates Total Applicable Sales x base cost 27,144,871 mWh x 2.8178¢/kWh	$764,888	
Fuel Expense to be Removed		($29,126)
Gross Receipts Tax to be Removed		
Gross Receipts Tax on ECR Revenue ($31,293) x 4.5%	($1,408)	
Gross Receipts Tax to be Removed		($1,408)
Total Expenses to be Removed		($30,534)
Increase in Taxable Income		$759
Income Tax @ 49.768%		378
Increase in Income for Return		$381

(a) Gross ECR Revenue - ($31,293)
Interest on Overcollections - Time of Use (1,324)
Net ECR Revenue ($32,617) (A-5)

Philadelphia Electric Company - Electric Operations
DEVELOPMENT OF RECOVERABLE ENERGY COSTS AND
ENERGY COSTS DEFERRED
12 Months Ended June 30, 1985
(Thousand $)

	Total Applicable Energy Costs (1)	Allocation Factor (2)	Allocated Energy Cost (3)	Recovered In Base Rates (4)	Recoverable (5)=(3)-(4)	Deferral ECR Revenue (6)	Deferral ECR Revenue Excl. GRT (7)=(6)x.955	Deferred (8)=(5)-(7)
Jul. 1984	86,668	.9776	84,727	71,784	12,942	814	777	12,165
Aug.	96,974	.9763	94,676	71,494	23,182	937	895	22,287
Sept.	63,837	.9774	62,394	62,264	130	770	735	(605)
Oct.	67,001	.9755	65,359	60,416	4,944	(171)	(163)	5,107
Nov.	93,715	.9758	91,447	58,417	33,030	(153)	(146)	33,176
Dec.	58,588	.9749	57,118	62,824	(5,706)	(461)	(440)	(5,266)
Jan. 1985	75,357	.9743	73,420	67,497	5,923	(469)	(448)	6,371
Feb.	72,464	.9741	70,587	69,300	1,287	(6,802)	(6,496)	7,783
Mar.	56,365	.9755	54,984	62,455	(7,471)	(8,859)	(8,460)	989
Apr.	48,582	.9758	47,406	59,951	(12,545)	(6,582)	(6,286)	(6,259)
May	42,181	.9770	41,211	58,621	(17,410)	(5,499)	(5,252)	(12,158)
June	43,700	.9775	42,716	59,865	(17,149)	(4,818)	(4,601)	(12,548)
	$805,432		$786,045	$764,888	$21,157	($31,293)	($29,885)	$51,042*

(a)

Account	Total	FOB Fuel Only	Non Fuel Chgs. Excluding Nucl. Spent Fuel	Nuclear Spent Fuel
501,504	$319,469	$316,130	$3,339	-
518	75,196	39,136	19,609	$16,451
547	20,869	20,780	89	-
555	451,553	439,016	12,537	-
Sub-Total	$867,087	$815,062	$35,574	$16,451
Less:Salem #2	5,944	3,282	2,020	642
Sub-Total	$861,143	$811,780	$33,554	$15,809
Less: HT Rider Energy	-	6,348	-	-
Total	$861,143	$805,432	$33,554	$15,809

* Deferral per books = $29,138. Included in the book deferred fuel account is a credit of $21,145 for fuel savings associated with Salem Unit No. 2. There is also a $759 adjustment for prior period corrections.

D-4a

Philadelphia Electric Company - Electric Operations
ANNUALIZATION OF WAGES, BENEFITS AND
NUMBER OF EMPLOYEES
($1,000)

This adjustment annualizes the increases in wage and benefits expenses effective August 1, 1984. In addition, this adjustment develops the increase in wage and benefit expenses effective August 1, 1985 not reflected in the test year. Additional discussion regarding this adjustment is contained in the Direct Testimony of T. P. Hill, Jr..

Wages - Total Company

June 1985 - Regular payroll (D-5a)	$29,541
Paid days - June 1985	20
Average payroll per paid day	$1,477.1
Average payroll per paid day revised for 8/1/85 increase (1,477.1 x 1.054)(a)	1,556.9
Annualized regular payroll at June 1985 ($1,556.9 x 261 days/year)	$406,351
Less: 12 months regular payroll (D-5a)	364,980
Increased Wage Expense	$41,371
Plus: Overtime at 17.5% (D-5a)	7,240
Increase in total payroll expense	$48,611

Pensions and Benefits - Total Company

Increase in Pensions and Benefits as a result of 8/1/84 package	$5,742
Estimated increase in pensions and benefits as a result of 8/1/85 package	3,271
Less: Portion of increase pensions and benefits included in test year	5,264
Total increase in Pensions and Benefits	$3,749

Total Increase in Wages, Pensions and Benefits

Total PE Company ($48,611 + $3,749)	$52,360
Total Allocated to Electric Operations $52,360 x 59.0% (b)	30,892
Decrease in Income Taxes @ 49.768%	15,374
Decrease in Income for Return	$15,518

(a) Actual 5.4% annual increase effective 8/1/85
(b) Page D-5a of Exhibit TPH-1

Philadelphia Electric Company

PAYROLL DATA
TWELVE MONTHS ENDED JUNE 30, 1985
(Thousand $)

Month	Total PE Company (1)	PE Company Electric Oper. (2)	PE Company Overtime (3)	PE Company Regular Payroll (4)=(1)-(3)	Electric Oper. As % of Total Payroll (5)=(2)/(1)	OT as % of PE Regular Payroll (6)=(3)/(4)	Number of Employees (7)
July 1984	34,138	20,423	4,811	29,327	59.8	16.4	10,739
August	37,019	21,457	5,073	31,946	58.0	15.9	10,680
September	33,329	19,681	5,370	27,959	59.1	19.2	10,448
October	37,997	22,441	5,608	32,389	59.1	17.3	10,481
November	37,087	21,301	5,684	31,403	57.4	18.1	10,480
December	34,681	20,212	4,811	29,870	58.3	16.1	10,513
January 1985	38,035	22,538	5,302	32,733	59.3	16.2	10,488
February	34,018	19,725	5,255	28,763	58.0	18.3	10,449
March	36,046	21,678	6,025	30,021	60.1	20.1	10,430
April	36,780	21,074	5,408	31,372	57.3	17.2	10,414
May	34,798	22,434	5,142	29,656	64.5	17.3	10,601
June	34,907	19,893	5,366	29,541	57.0	18.2	10,803
Total	428,835	252,857	63,855	364,980	59.0	17.5	10,544 (Avg.)

Philadelphia Electric Company - Electric Operations

ADJUST BOOK DEPRECIATION ACCRUAL TO REFLECT
YEAR-END PLANT AS OF JUNE 30, 1985
(Thousand $)

Additional information regarding this adjustment is contained in the Direct Testimony of A. Wroblewski.

Total Depreciation accrual Associated with Plant for Ratemaking purposes (C-5)	$236,877
Anti-Trust Price Adjustment	(644)
Allocated Common Depreciation Accrual, excluding Transportation (C-6)	4,338
Calculated Depreciation Accrual	$240,571
Less: Experienced Net Salvage Expense	(3,380) (1)
Total Calculated Depreciation Including Net Salvage Expense	$243,951
Book Depreciation Accrual and Amortization Excluding Decommissioning (B-13)	156,972
Increase in Depreciation Accrual	$86,979
Decrease in Income for Return	$86,979

(1) Development of experienced net salvage expense for five years ended June 30, 1985 utilizing methodology adopted by the Commission in its Order at R-842590.

	Salvage	
	Electric	Common
1980 (6 months)	(895)	(600)
1981	(271)	(170)
1982	(3,757)	397
1983	(3,907)	572
1984	(5,673)	(180)
1985 (6 months)	(3,382)	1,127
Five Year Average excluding Common	($3,577)	$229
Electric's Share of Common @ 86.188% (B-17)	197	
Total	($3,380)	

Philadelphia Electric Company
Increase in Income Tax by Computing
Tax Depreciation on Year-End Base
As of June 30, 1985
(Thousand $)

Refer to the Direct Testimony of G. A. Sileo for additional discussion of this adjustment.

Tax Depreciation and Amortization Year Ended June 30, 1985 Electric (D-7a)				
Tax Depreciation on Limerick #1 (D-7a, TPH-2)				$174,768
Common (D-7a)				262,069
Allocated To:	Per B-17			
Electric	86.188%	$4,744		
Gas	12.930	712		4,744
Steam	0.882	48		
Total	100.000%	$5,504		
Electric including allocated common				$441,581
Less: Amortization of Anti-trust Settlement for Tax Purposes				400
Total Allowance Tax Depreciation & Amortization on year-end Basis at June 30, 1985				$441,181
Less: Tax Depreciation accrued per books for 12 months ending June 30, 1985 including allocated Common				
Book Depreciation (B-13)			$157,911	
Amortization of Anti-Trust (B-13)			(644)	
Add: Transportation Depreciation Charged to Clearing				
	Per B-17			
Electric	86.188%	698	$698	
Gas	12.930	105		
Steam	0.882	7		
Total	100.000%	$810		
Excess of Tax Depreciation and Amortization over Book Depreciation (B-15)			$23,258	
Total Accrued Tax Depreciation and Amortization for 12 Months Ended June 30, 1985				$181,223
Total Increase in Tax Depreciation and Amortization				$259,958
Decrease in Income Taxes @ 49.768%				$129,376
Increase in Income for Return				$129,376

Philadelphia Electric Company - Electric Operations
Depreciable Tax Bases and Resulting Depreciation
As of June 30, 1985
(Thousand $)

Electric	Depreciation Base For Taxes (a)	Depreciation Rate For Taxes (b)	Tax Depreciation (c)
S/L Plant Installed Prior to 1954	$291,623	0.13%	$373
Liberalized Plant Installed 1954-1969	227,090	9.49	21,541
Liberalized Plant Installed 1970	33,512	12.48	4,181
Liberalized Plant Installed 1971	29,396	17.80	5,233
Liberalized Plant Installed 1972	18,766	14.30	2,684
Liberalized Plant Installed 1973	33,201	14.99	4,977
Liberalized Plant Installed 1974	102,940	19.92	20,501
Liberalized Plant Installed 1975	30,606	12.30	3,952
Liberalized Plant Installed 1976	59,995	13.49	8,091
Liberalized Plant Installed 1977	88,780	18.51	16,430
Liberalized Plant Installed 1978	28,964	11.45	3,317
Liberalized Plant Installed 1979	37,542	11.68	4,386
Liberalized Plant Installed 1980	39,368	11.09	4,367
Liberalized Plant Installed 1981	91,834	15.93	14,630
Liberalized Plant Installed 1982	189,248	11.42	21,605
Liberalized Plant Installed 1983	121,249	11.74	14,234
Liberalized Plant Installed 1984	127,091	11.76	14,946
Liberalized Plant Installed 1985	94,593	9.85	9,320
Total	$1,645,798		$174,768
Tax Depreciation - Common			
S/L Plant Installed Prior to 1954	$5,961	1.88%	$112
Liberalized Plant Installed 1954 to 1969	5,785	4.81	287
Liberalized Plant Installed 1970	1,005	6.77	68
Liberalized Plant Installed 1971	245	8.98	22
Liberalized Plant Installed 1972	25,221	4.43	1,117
Liberalized Plant Installed 1973	961	5.41	52
Liberalized Plant Installed 1974	358	8.66	31
Liberalized Plant Installed 1975	328	6.10	20
Liberalized Plant Installed 1976	187	5.88	11
Liberalized Plant Installed 1977	590	5.42	32
Liberalized Plant Installed 1978	700	5.14	36
Liberalized Plant Installed 1979	1,706	5.33	91
Liberalized Plant Installed 1980	1,250	7.20	90
Liberalized Plant Installed 1981	3,043	17.09	520
Liberalized Plant Installed 1982	4,420	33.87	1,497
Liberalized Plant Installed 1983	3,213	17.62	566
Liberalized Plant Installed 1984	4,194	14.62	613
Liberalized Plant Installed 1985	2,442	13.88	339
Total	61,609		5,504

(a) Plant in Service at 6/30/85 less tax reserves as of 7/1/85.
(b) Depreciation rates are composites based on plant life estimates which are prescribed by U.S. Treasury Guideline Regulation as modified in the Revenue Acts of 1971, 1981 and 1982.
(c) Liberalized Tax Depreciation has been computed under the declining balance method, switched to either straight line or sum-of-the-years method as appropriate.

Philadelphia Electric Company - Electric Operations
NORMALIZATION OF TAX DEFERRALS ON YEAR-END PLANT
AND ELIMINATION OF TAX DEFERRALS FROM 1970 TAX
LEGISLATION REFLECTED ON D-1
(Thousand $)

Refer to the Direct Testimony of G. A. Sileo for further discussion of this adjustment.

Plant		
Excess Depreciation (a) (D-8a)		$55,425
Excess Depreciation - Limerick No. 1 (D-8a,TPH-2)		202,796
Common Allocated to Electric (b)		1,487
Total		$259,708
Tax Deferral on 6/30/85 Plant @ 46%		$119,466
Tax Deferral on Plant Per Books (c)	$23,185	
Less: Deferred Tax Removed through STAC		
A/C Excess Depreciation on Plant (D-1)	523	
Net Per Books		$22,662
Change in Tax Deferral on Plant		$96,804
Fuel		
Fuel Expense Deferred		
12 Months ended 6/30/85		$50,283
Tax Deferral on fuel @ 49.768%		25,025
Tax Deferral on Fuel per books (c)	$25,446	
Less: Deferred tax removed through STAC		
A/C Deferred (D-1)	421	
Net per books		25,025
Change in tax deferred on fuel		0
Decrease in Income for Return		$96,804

(a) The amounts reflected represent normalization of tax deferrals, generated by the use of liberalized tax depreciation for plant additions increasing capacity and installed after 1969 and before 1981, plus the deferral resulting from use of the Class Life System (ADR) of the Revenue Act of 1971. Pursuant to the Pa.P.U.C. Order dated 8/17/73 at RID 29, these figures exclude depreciation on plant replacing capacity. The amounts also reflect normalization of tax deferrals assocated with all public utility property placed in service after 1980 under the Economic Recovery Tax Act of 1981.

(b) Allocation of Common:

	Percent (B-17)	Depreciation Subject to Normalization
Electric	86.188	$1,487
Gas	12.930	223
Steam	0.882	15
Total	100.000%	$1,725 (D-8a)

(c) Total provision for deferred income taxes as shown on B-9 is comprised as follows:

Portion a/c capitalized Pensions & Taxes	6,163
Portion a/c capitalized Employee Benefits	3,245
Portion a/c deferred fuel cost	25,446
Portion a/c state carryover loss adjustment	181
Portion a/c excess depreciation on Plant	23,185
Portion a/c nuclear fuel	56
Portion a/c Recoverable Purta	8,118
Portion a/c Interest on Capital Stock Assessment	393
Portion a/c Nuclear fuel storage	3,390
Portion a/c Decommissioning expense	924
Portion a/c Turbine lease cancellation	2,495
Portion a/c Schuylkill Plant	843
Portion a/c other deferred taxes	273
Total Deferred Income Taxes	$74,712

Philadelphia Electric Company
Tax Depreciation Subject To Normalization
June 30, 1985
(Thousand $)

	Depreciation Base			Depreciation Rate		Depreciation		
	For S/L Base (1)	Tax Reserve (2)	For Liberalized Base (3)=(1)-(2)	Liberalized (4)=(6)/(3)	S/L (5)=(7)/(1)	Liberalized (6)	S/L (7)	Excess (8)=(6)-(7)
Electric Plant								
1970	$117,784	$87,584	$30,200	13.10%	3.39%	$3,957	$3,988	($31)
1971	141,673	116,525	25,148	19.07	3.39	4,795	4,799	(4)
1972	69,567	54,653	14,914	15.64	3.28	2,332	2,279	53
1973	110,666	84,071	26,595	16.53	3.40	4,397	3,759	638
1974	497,656	401,563	96,093	20.49	4.27	19,694	21,241	(1,547)
1975	70,457	48,762	21,695	14.76	3.47	3,203	2,443	760
1976	157,008	98,833	58,175	13.65	3.55	7,939	5,571	2,368
1977	283,265	197,730	85,535	18.89	4.68	16,159	13,263	2,896
1978	52,288	27,191	25,097	11.89	3.60	2,984	1,880	1,104
1979	60,827	29,599	31,228	12.33	3.87	3,850	2,351	1,499
1980	60,107	25,013	35,094	11.49	3.92	4,034	2,356	1,678
1981	164,367	72,533	91,834	15.93	3.22	14,630	5,285	9,345
1982	270,328	81,080	189,248	11.42	3.83	21,605	10,367	11,238
1983	155,015	33,766	121,249	11.74	3.11	14,234	4,820	9,414
1984	143,361	16,270	127,091	11.76	3.68	14,946	5,275	9,671
1985	97,896	3,303	94,593	9.85	3.04	9,320	2,977	6,343
Total	$2,452,265	$1,378,476	$1,073,789			$148,079	$92,654	55,425
Common Plant								
1970	$2,566	$1,645	$921	6.84%	1.79%	$63	$46	$17
1971	2,643	2,573	70	18.57	0.49	13	13	-
1972	39,614	18,267	21,347	4.44	2.17	948	859	89
1973	4,004	3,114	890	5.28	1.02	47	41	6
1974	1,185	1,000	185	11.89	1.60	22	19	3
1975	1,807	1,658	149	8.72	0.61	13	11	2
1976	3,235	3,157	78	7.69	0.15	6	5	1
1977	1,242	769	473	5.29	2.50	25	31	(6)
1978	1,126	542	584	4.97	2.84	29	32	(3)
1979	2,545	941	1,604	5.11	3.69	82	94	(12)
1980	1,744	600	1,144	7.26	4.01	83	70	13
1981	6,744	3,701	3,043	17.09	7.40	520	499	21
1982	10,036	5,616	4,420	33.87	8.06	1,497	809	688
1983	4,580	1,367	3,213	17.62	5.39	566	247	319
1984	4,887	693	4,194	14.62	4.89	613	239	374
1985	2,578	136	2,442	13.88	4.89	339	126	213
Total	$90,536	$45,779	$44,757			$4,866	$3,141	$1,725

Philadelphia Electric Company - Electric Operations
ADJUSTMENT OF INCOME TAXES TO REFLECT
PRO FORMA INTEREST CHARGES BASED ON
YEAR-END PLANT AND EMBEDDED COST OF DEBT
As of June 30, 1985

D-9

As permitted by the Pa. P.U.C. order dated August 17, 1973, the Company adopted Income Tax Allocation effective October 1, 1973, under which electric operating income is credited with the tax savings on interest charges associated with debt issued to finance plant actually in service.

This adjustment is necessary to reflect the pro forma interest charges on the Company's rate base as of June 30, 1985 and the 10.74% embedded cost of debt at 6/30/85 (Page B-19). Refer to the Direct Testimony of G.A. Silso for additional information regarding this adjustment.

	(Thousand $)
Actual Test Year Interest Charges Allocated To Electric in Developing Operating taxes (B-15)	193,578
Pro Forma Interest Charges Allocable to Electric Based on Rate Base Claim	
O.C. Measure of Value at 6/30/85 (A-2)	7,014,234
% Financed by Debt	51.5
Amount Financed with Debt	3,612,331
Pro Forma Interest Charges @ 10.74%	387,964
Increase in Interest Charges Allocated	194,386
Change in Income Taxes @ 49.768%	(96,742)
Increase in Income for Return	96,742

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC OPERATIONS

ADJUSTMENT TO ACTUAL
NUCLEAR AND FOSSIL PLANT PRODUCTION
OPERATION AND MAINTENANCE EXPENSES
FOR THE TEST YEAR ENDING
June 30, 1985
($1,000's)

Actual expenses must be reviewed and adjusted, when necessary, to conform with normalized levels appropriate for ratemaking purposes. The adjustment below reflects the increase in test year expenses resulting from the difference between actual and normalized level of expenses for Electric Production O&M. In addition, this adjustment reflects the amortization of non-recurring costs associated with the Salem Management Evaluation Program. A detailed explanation of these expenses is provided in the Direct Testimony of J. J. Carroll.

Nuclear Plant O&M Increases (D-10a)	$6,654
Fossil Plant O&M Increases (D-10b)	2,455
Salem Management Evaluation Program - Decrease (D-10c)	(2,382)
Net Increase in O&M Expenses	$6,727
Income Tax @ 49.768%	3,348
Decrease In Income for Return	$3,379

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC OPERATIONS

Adjustment to Actual Operation and Maintenance
Expense for Nuclear Plants
To Reflect a Normalized 2/3 Outages Per Unit Per Year
For the Test Year Ending June 30, 1985
($1,000)

Normalized Outage Expenses		
Peach Bottom Station	$12,034	
Salem No. 1 Unit	5,320	
Salem No. 2 Unit	5,320	
Limerick #1 Unit	13,067	
		$35,741
Actual Outage Expenses		
Peach Bottom Station	$11,715	
Salem No. 1 Unit	10,483	
Salem No. 2 Unit	6,889	
Limerick No. 1 Unit	0	
		$29,087
Adjustment to O&M (D-10)		$6,654

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC OPERATIONS

Adjustment to Actual Operation and Maintenance
Expenses for Fossil Plants
To Reflect a Normalized Level of Outages
For the Test Year Ending June 30, 1985
($1,000)

Normalized Expenses	$21,802
Actual Outage Expenses	19,347
Adjustment to O&M (D-10)	$2,455

Philadelphia Electric Company - Electric Operations

ADJUSTMENT TO OPERATION & MAINTENANCE
EXPENSE TO REFLECT THE AMORTIZATION
OF COSTS ASSOCIATED WITH THE SALEM
MANAGEMENT EVALUATION PROGRAM
12 Months Ended June 30, 1985
($1,000)

The purpose of this adjustment is to amortize over a two-year period the costs associated with the Salem Management Evaluation Program that are non-recurring. Additional information on this adjustment is contained in the Direct Testimony of J. J. Carroll.

Annual Amortization of Non-Recurring Expense ($7,283/2)	$3,642	
Non-Recurring Expense Included in Test Year	6,024	
Reduction in Test Year Expense		$2,382

Philadelphia Electric Company - Electric Operations

Adjustment to Reflect Decrease in Operation and Maintenance Expense for Retirements in the Test Year Ending June 30, 1985
(Thousand $)

The purpose of this adjustment is to eliminate from actual operation and maintenance expense all expenses associated with production plant that is being retired. Refer to the Direct Testimony of J. J. Carroll for further detail.

Retirement of Richmond No. 9 Unit	
Operating and Maintenance Expense (less fuel)	$2,272
Retirement of scheduled Internal Combustion Units - Richmond No.'s 21, 22, 31, 32, 41, 42, 43, 44, 51, 52, 61, 62, 71 72, 73 and 74, Plymouth Meeting No's 9 and 15 and Southwark Diesel	
Operating and Maintenance Expense (less fuel)	5,450
Retirement of Southwark No.'s 1 and 2	
Operating and Maintenance Expense (less fuel)	5,373
Total Decrease in O&M	$13,095
Income Tax @ 49.768%	6,517
Increase in Income for Return	$6,578

Philadelphia Electric Company - Electric Operations
AMORTIZATION OF ADJUSTMENTS ORDERED
IN PRIOR CASES AND PROPOSED AMORTIZATION
OF CURRENT EXPENSES
JUNE 30, 1985
($1,000)

In prior proceedings the Commission, for ratemaking purposes, provided for the amortization of certain expense items. Developed below is the adjustment to book expense to reflect these prior period items together with the company's claim for current rate case and abandoned engineering expenses. Additional discussion of this adjustment is provided in the Direct Testimony of T. P. Hill, Jr..

	Amount Booked In Test Year (1)	Ratemaking Claim (a) (2)	Adjustment (3)=(2)-(1)
1. Rate Case Expenses			
- RID 129,295,438,865	-	132	132
- R-842590	189	-	(189)
- Current Case	2,615	1,340	(1,275)
- ECR #8	1,470	116	(1,354)
- ECR #9	-	300	300
- Limerick #2 Show Cause	4,362	1,100	(3,262)
2. Turbine Lease Cancellation	10,027	-	(10,027)
3. Storm Damage	(871)	261	1,132
4. Office Automation Equip.	330	86	(244)
5. Abandoned Engineering Chester Station	-	40	40
6. Eddystone #1 Restoration	-	1,877	1,877
Subtotal Change in O&M			($12,870)
Change in Income Taxes a/c O&M expenses @ 49.768%			$6,405
7. Def. Taxes-State Tax Rate Chg	(224)	(425)	(201)
8. Pioneer Uravan Amortization	190	459	269
9. Abandoned Engineering Heaton-Byberry 230 kv line	445	89	(356)
Total Incr. in Income for Return [$12,870-(6,405-201+269-356)]			$6,753

(a) For detail see Page D-12a.

Philadelphia Electric Company - Electric Operations
DEVELOPMENT OF RATEMAKING CLAIM FOR
CERTAIN EXPENSE ITEMS
($1,000)

Item	Case Authorizing Authorization	Original Amount to be Amortized	Amortized as of 6/30/85	Unamortized as of 6/30/85	Current Year's Claimed Amortization
1. Rate Case Expenses					
- RID 129, 295, 438, 865	R-811626	2,755	1,954	801	132
- Current Case		2,680	-	2,680	1,340 (1)
- ECR #8	R-842590	1,650	321	1,329	116
- ECR #9		600	-	600	300 (1)
- Limerick #2 Show Cause		5,500	-	5,500	1,100 (2)
2. Amort. of Turbine Lease Cancellation	R-811626	40,108	30,917	9,191	-
3. Storm Damage	R-842590	1,000	145	855	261 (3)
4. Office Automation Start-up Costs	R-842590	330	48	282	86 (3)
5. Abandoned Engr. Chester Station	R-801225	970	727	243	40 (3)
6. Eddystone #1 Restoration	R-842590	7,185	1,041	6,144	1,877 (3)
7. State Tax Rate Change	R-842590	(3,018)	(438)	(2,580)	(787)(4)
8. Pioneer Uravan,	R-842590	2,296	200	2,096	459
9. Abandoned Engineering Heaton Byberry 230 kv line		445	-	445	89 (2)

(1) Reflects a 2 year normalization
(2) Reflects a 5 year normalization
(3) Reflects a 2 year amortization of the unamortized balance
(4) Current year net of Deferred Federal Income Tax effect = (425); 2 year amortization of unamortized balance

Philadelphia Electric Company - Electric Operations
ADJUSTMENT TO ELIMINATE THE REVENUE
AND FUEL EXPENSE ASSOCIATED WITH SALES
TO BOTH THE BOROUGH OF LANSDALE AND TO
JERSEY CENTRAL POWER & LIGHT THAT ARE
INCLUDED IN THE TEST YEAR ENDED
JUNE 30, 1985
(Thousand $)

Effective on 12/31/84, Jersey Cental Power & Light no longer purchases the output of Salem #2 from PECo. In addition effective 7/85, the Borough of Lansdale will no longer receive its power supply from the Philadelphia Electric Company. The purpose of this adjustment is to eliminate all revenues and fuel expenses associated with sales to Lansdale and Jersey Central Power & Light from the 6/30/85 test year. Refer to the Direct Testimony of R. W. Wright for a more detailed description of this adjustment.

	Lansdale	JCP&L	Total
Revenue included in test year	$7,847	$28,932	$36,779
Less: Fuel	3,585	5,147	8,732
Taxable income to be removed	$4,262	$23,785	$28,047
Decrease in income taxes	2,121	11,837	13,958
Decrease in income for return	$2,141	$11,948	$14,089

Philadelphia Electric Company - Electric Operations
FEDERAL OLD AGE BENEFITS
FOR THE YEAR ENDED 6/30/85
(Thousand $)

Effective 1/1/85 the wage base subject to federal old age benefits tax increased to $39,600 from $37,800 and the rate of tax increases from 7.00% to 7.05%. Additional discussion of this adjustment is contained in the Direct Testimony of G. A. Sileo.

Developed below is the increase in expense on account of the above increase.

Total Company

7/1/84 to 6/30/85 FICA Wage Base @ $39,600	$341,619
Full year effect of 7.05% FICA Rate ($341,619 x 7.05%)	24,084
7/1/84 to 6/30/85 Expense Included in Test Year	21,481
Increase	$2,603
Allocation to Electric Operations	
$2,603 x 59.0% (a)	$1,536
Decrease in income taxes @ 49.768%	764
Decrease in income for return	$772

(a) Based on 12 months ended June 30, 1985 (Ref: Page D-5a of Exhibit TPH-1)

Philadelphia Electric Company - Electric Operations
DECOMMISSIONING COST ADJUSTMENT FOR
PEACH BOTTOM NO. 1, 2 & 3, SALEM NO. 1 & 2 AND LIMERICK NO. 1
12 Months Ended June 30, 1985
($1,000's)

In its order at R-842590, the Commission permitted the Company an annual accrual for decommissioning expense of four nuclear units - Peach Bottom Units No. 2 and No. 3 and Salem Units No. 1 and No. 2. Subsequent to this order the Company performed a new decommissioning cost study for all our nuclear plants. This adjustment utilizes the new study to (1) include Peach Bottom Unit No. 1 and Limerick Unit No. 1 in the estimate (2) reflect the increase in the total estimated cost of decommissioning (3) provide recovery of the reserve deficiency over a five year period for historic accruals for Peach Bottom Units No. 2 and No. 3 and Salem Units No. 1 and No. 2 and (4) recover future accruals through the year 2008 for the Peach Bottom and Salem Units and through the year 2024 for Limerick Unit No. 1. The Direct Testimony of N. B. McLeod provides a discussion of the decommissioning study performed for all of the Company's nuclear units. The Direct Testimony of R. W. Wright provides a description of the Company's expense accounting.

Development of Future Annual Accrual for Decommissioning

PECo share of estimated total cost of decommissioning: (6/30/86)		
- Peach Bottom Units No.1,No.2,No.3	$107,257	
- Salem Units No.1, No.2	76,684	
- Limerick Unit No.1	123,629	
	$307,570	
Annual decommmissioning expense		
- Peach Bottom Units No.1, No.2, No.3		3,979
- Salem Units No.1, No.2		2,789
- Limerick Unit No. 1		3,253
		$10,021

Expense to Correct Prior Accruals

Reserve requirement at 6/30/85 for Peach Bottom Units No. 2 and 3 and Salem Units No. 1 and No. 2	$29,219	
Actual reserve through 6/30/85 including interest	15,746	
Increase in Decommissioning Expense necessary to correct prior accruals	13,473	
5 yr amortization of incr. in decommissioning expense to correct prior accruals		2,695
Total expense associated with decommissioning		12,716
Decommissioning expense included in test year		3,832
Increase in Decommissioning Expense		$8,884
Decrease in Income Taxes @ 49.768%		4,421
Decrease in Income for Return		$4,463

Philadelphia Electric Company - Electric Operations

SPENT FUEL DISPOSAL COST ADJUSTMENT
FOR PEACH BOTTOM NO. 2 & 3, SALEM NO. 1 & 2, AND LIMERICK NO. 1
12 Months Ending June 30, 1985
($1,000)

In its order at R-842590, the Commission permitted the Company spent fuel expense allowances for Peach Bottom Units No. 2 and No. 3 and Salem Units No. 1 and No. 2 based on an estimate by DOE of 1 mill/kWh of gross electrical output for spent fuel removal beginning on April 7, 1983.

The purpose of this adjustment is to include in test year operating expenses the Company's cost for spent fuel removal.

This claim applies the DOE assessment of 1 mill/gross kWh to the anticipated average annual generation by Peach Bottom Units No. 2 and No. 3, Salem Units No. 1 and No. 2 and Limerick Unit No. 1. The Direct Testimony of J. J. Carroll provides detail on the development of anticipated average annual nuclear generation. Also, refer to the Direct Testimony of R. W. Wright for a detailed description of the Company's spent fuel expense accounting.

Estimated Annual Spent Fuel Expense:	
Peach Bottom 2	$2,647
Peach Bottom 3	2,600
Salem 1	2,754
Salem 2	2,827
Limerick 1	6,247
Total Expense Associated with Spent Fuel Removal	$17,075
Less: Spent Fuel Included in Test Year	16,451
Increase in Spent Fuel Expense	$624
Change in Income Taxes @ 49.768%	311
Decrease in Income for Return	$313

Philadelphia Electric Company - Electric Operations

ADJUSTMENT TO AMORTIZE THE LOSS ON
THE SALEM #1 DAMAGED NUCLEAR FUEL ASSEMBLIES
(Thousand $)

During the course of a PUC 1982 fuel audit approximately $929,000 related to damaged nuclear fuel assemblies was eliminated from recoverable fuel costs. The purpose of this adjustment is to amortize the cost of Salem #1 damaged nuclear fuel assemblies to base rates over a period of three years. The amount being amortized is equal to the amount of the adjustment in the 1982 Pa.PUC fuel audit. Refer to the Direct Testimony of T. P. Hill, Jr. for further discussion of this adjustment.

Total to be amortized	$929
Annual amortization (3 years)	$310
Decrease in deferred taxes @ 49.768%	154
Decrease in Income for Return	$156

Philadelphia Electric Company - Electric Operations

Adjustment to Reflect Full Year O&M Expenses
for Limerick No. 1 Unit
(Thousand $)

This adjustment is necessary to reflect a full year effect of the operating and maintenance expenses associated with Limerick No. 1 Unit which were not included in the original budget data.

Additional information regarding nuclear O&M expenses is contained in the Direct Testimony of J. J. Carroll. Refer to the Direct Testimony of T. P. Hill, Jr. for additional discussion regarding pensions, benefits, insurance and payroll taxes.

Description	Accounts	Amount	
Nuclear O&M Expenses	517 to 532	$63,448	(Carroll)
Pensions and Benefits	926	6,408	(Hill)
Insurance	924, 925	5,534	(Hill)
Payroll Taxes	950	350	(Hill)
Total Annual O&M		$75,740	
Amount Included in Budget		0	
Increase in O&M Expense		$75,740	
Decrease in Income Taxes		37,694	
Decrease in Income for Return		$38,046	

Philadelphia Electric Company - Electric Operations

NON JURISDICTIONAL RATES
RATE OF RETURN ADJUSTMENT
12 Months Ending June 30, 1985
(Thousand $)

As per the Company's cost of service study, Exhibit WFS-1, the current return level from those customers not subject to Pennsylvania regulation is lower than the overall Company average return being sought in this case. The purpose of this adjustment is to reflect the additional income which results from applying the system average return to these customers. Refer to the Direct Testimony of T. P. Hill, Jr. for additional discussion of this adjustment.

	FERC Jurisdiction	Interdepartmental	Total
Revenue at proposed return level (12.70%)	$29,633	$4,803	$34,436*
Less: Revenues included in June 30, 1985 test year	27,034	4,266	31,300
Additional Revenue	$2,599	$537	$3,136
Decrease in fuel expense @ 491,712,722 kWh (a) @ .7355¢/kWh (D-21)			3,617
Increase in taxable income			6,753
Income taxes @ 49.768%			$3,361
Increase in income for return			$3,392

*Assumes full rate increase is granted. Therefore, this is subject to change if a portion of the increase is disallowed.

(a) FERC 427,601,757 kWh
Interdepartmental 64,110,965 kWh
491,712,722 kWh

Philadelphia Electric Company - Electric Operations

ADJUSTMENT TO REFLECT FULL YEAR AMORTIZATION OF
INVESTMENT TAX CREDIT
ON A YEAR-END PLANT BASIS
12 MONTHS ENDED JUNE 30, 1985
(Thousand $)

The purpose of this adjustment is to reflect a full year's amortization of investment tax credit on qualifying plant placed in service during the test year assuming the proforma proposed rates were in effect during this period. The effect of the adjustment is to place the ITC amortization on a year-end plant basis. Additional information on this adjustment is contained in the Direct Testimony of G. A. Sileo.

Amortization on the $50,609 Plant in Service Portion of the total $132,410 ITC Carryover at 6/30/85 (per B-15)	3,859	
Amortization of Limerick Unit 1 with 100% Common	4,997	
Annualization Adjustment for Plant in Service Portion of ITC Carryover		$8,856*
Increase in ITC Amortization		$8,856
Increase in Income Available for Return		$8,856

*Assumes full rate increase is granted. Therefore it is subject to change if a portion of the increase is disallowed.

PHILADELPHIA ELECTRIC COMPANY - ELECTRIC OPERATIONS

Adjustment to Base Rates to Reflect
A Roll-out of .7505¢/kWh of Fuel Expense
(Thousand $)

Effective with the commercial operation date of Limerick Unit #1, it is expected that the Company's energy costs will be significantly reduced. The purpose of this adjustment is to reflect the effect of this cost reduction through a .7505¢/kWh roll-out of fuel from base rates. The development of the fuel roll-out is shown below. Refer to the Direct Testimony of J. J. Carroll for further discussion on the development of the energy savings.

Decrease in Revenue (D-21a)		$205,975
Decrease in Fuel Expense	$201,855	
Decrease in Gross Receipts Tax	4,120	
Total Decrease in Expense		$205,975
Change in Taxable Income		$0

Philadelphia Electric Company - Electric Operations

Adjustment to Base Rates to Reflect
A Roll-Out of .7505¢/kWh
of Fuel Expense
(Thousand $)

Total Fuel & Interchange Expense without Limerick No. 1 Unit 7/1/86 to 6/30/88	$1,378,043
Total Fuel & Interchange Expense with Limerick No. 1 Unit 7/1/86 to 6/30/88	$961,407
Reduction in Fuel & Interchange Expense resulting from Limerick No. 1 Unit supplying PECo System Sales	$416,636
PECo System Sales from 7/1/86 to 6/30/88	56,647,100 Mwh
Reduction in Cost per kWh $\frac{\$416,636,000}{56,647,100\ MWh}$ =	7.355 M/kWh
Tax Effect 1/1-T (T=2.0%)	1.02041
Reduction in Energy Cost per kWh	7.505 m/kWh
Applicable Sales for Test Year (Adjusted for Growth)	27,444,997 MWh
Decrease in Revenue	$205,975

EXHIBIT TPH-2

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PHILADELPHIA ELECTRIC COMPANY
ELECTRIC OPERATIONS

REVENUE, EXPENSES, INCOME & MEASURES OF VALUE

TWELVE MONTHS ENDING
JUNE 30, 1986

SEPTEMBER, 1985

Philadelphia Electric Company - Electric Operations A-1

INCOME AVAILABLE FOR RETURN

12 MONTHS ENDED JUNE 30, 1986

(Thousand $)

	Actual (B-9)	Adjustments (A-3)	Proforma Pres. Rates	Addl. Revs. (A-4)	Proforma Proposed Rates
Operating Revenue	2,520,293	(26,300)	2,501,993	681,760	3,183,753
Operating Expenses					
Operating & Maintenance Exp.	1,502,703	145,544	1,648,247	(206,990)	1,441,257
Depn. & Amort. (incl. salvage)	164,429	100,448	264,877		264,877
Provision for Taxes					
Taxes Other Than Inc.	199,837	(113,785)	86,052	13,635	99,687
Income Taxes	138,673	(98,641)	34,032	435,527	469,559
Provision for Deferred Taxes	107,815	(66,804)	41,011		41,011
Income Taxes Def.-Other	(14,032)	427	(13,606)		(13,606)
ITC Adjustment-(net)	6,912	(10,313)	(3,401)		(3,401)
Total Taxes	433,204	(289,116)	144,088	449,162	593,250
Total Operating Expenses	2,100,336	(43,124)	2,057,212	242,172	2,299,384
Operating Income Avail. for Return	427,957	16,824	444,781	439,588	884,369
Original Cost Measure of Value (A-2)			6,963,532		6,963,532
Return on Original Cost			6.39		12.70

RATE OF RETURN COMPONENTS

	Ratio	Cost	Wtd. Cost
DEBT (B-19a)	0.507	10.84	5.50
PREFERRED (B-20)	0.108	10.54	1.14
COMMON EQUITY	0.385	15.75	6.06
			12.70

Philadelphia Electric Company - Electric Operations
MEASURES OF VALUE
AT JUNE 30, 1986
(Thousand $)

	Reference	Original Cost
Utility Plant in Service		
Electric	C-2	8,757,719
Allocated Common	C-2	122,807
Total O.C. Plant in Service		8,880,526
Less: Book Reserve on Plant in Service	C-2	1,665,850
		7,214,676
Plus: Non-Revenue Producing CWIP	C-8	4,657
Land Held for Future Use	C-9	8,651
Materials and Supplies	C-10	90,550
Nuclear Fuel in Reactor	C-11	82,252
Cash Working Capital	C-12	99,351
Total Additions		285,461
Less: Accumulated Deferred Inc. Taxes		
Accelerated Amortization	B-2	2,323
Liberalized Depreciation	B-16	526,166
Customer Deposits	B-2	7,682
Customer Advances	B-2	434
Total Deductions		536,605
Measures Of Value		6,963,532

Philadelphia Electric Company - Electric Operations

ADJUSTMENTS TO INCOME AVAILABLE FOR RETURN

12 Months Ended June 30, 1986

(Thousand $)

Test Year Adjustments	Section Page	Operating Revenues	Oper. Exp. Excl. Taxes	Taxes Other Than Income	State Share Income Taxes	Federal Share Income Taxes	Effect on Income for Return
Elimination of STAC Revenue and Taxes	D-1	(125,007)		(117,721)	(8,286)		0
Full Year Effect of Present Base Rates	D-2	0		0	0	0	0
Annualization for Growth and Customers	D-3	36,771	13,805	775	1,688	10,351	12,152
Elimination of Energy Cost Adjustment	D-4	53,711	51,891	2,480			0
Wage and Benefit Increases	D-5		5,695		(397)	(2,437)	(2,861)
Book Depn at Year End, including Salvage	D-6		91,747				(91,747)
Tax Depreciation and Amort. at Year End	D-7				5,418	33,226	(38,644)
Normalization of Tax Deferrals	D-8				0	(70,025)	70,025
Tax Savings on Proforma Interest	D-9				(13,613)	(83,490)	97,103
Nuclear and Steam Prod. O&M Exp. Adj.	D-10		12,586		(874)	(5,360)	(6,298)
Reduction in O&M exp. to Reflect Retire.	D-11		(10,556)		736	4,518	5,302
Miscellaneous Adjustments & Amortization	D-12		(4,852)		377	2,891	1,584
Elimination of Lanadale Revenue and Fuel	D-13	0	0		0	0	0
Full Year Effect of Incr. in FICA Tax	D-14			741	(52)	(317)	(372)
Decommissioning Cost Adjustment	D-15		8,701		(607)	(3,723)	(4,371)
Spent Fuel Disposal Cost Adjustment	D-16		5,350		(374)	(2,294)	(2,692)
Damaged Nuclear Fuel Assbly. Amort.	D-17		310		(22)	(132)	(156)
Full Year of Limerick O&M Expense	D-18	0	75,740		(5,284)	(32,410)	(38,046)
Non-Jurisdictional Rate of Return	D-19	7,225	(3,775)		767	4,707	5,526
ITC Annualization	D-20				0	(10,313)	10,313
Adjustment to Roll Fuel Out of Base Rate	D-21*	(211,214)	(206,990)	(4,224)			0
Total		(25,300)	245,992	(113,785)	(20,523)	(154,808)	16,824

* Not included in totals; Reflected on A-4

Philadelphia Electric Company - Electric Operations
EFFECTS ON INCOME FOR RETURN
OF SUPPLEMENT NO. 15
12 Months Ending June 30, 1986
(Thousand $)

	Increase in Base Rates		
	Base Rate Increase Prior To Fuel Roll-out	Fuel Roll-out From Base @ $.007505/kwh Per D-21	Net Base Rate Increase
Increase in Revenue (A-5)	892,974	(211,214)	681,760
Less: 2% Gross Receipts Tax	17,859	(4,224)	13,635
Less: Fuel Rolled-out of Base		(206,990)	(206,990)
Increase in Income Before Taxes	875,115	0	875,115
Increase in Income Taxes 049.768%	435,527	0	435,527
Increase in Income for Return	439,588	0	439,588

Philadelphia Electric Company - Electric Operations
Kilowatt Hour Sales and Revenue by Tariff Subdivisions
Twelve Months Ended June 30, 1986
($1,000)

	mWh Sales Year Ended 6/30/86 (1)	Number of Customers 6/30/86 (2)	Total Book Rev (3)	Less: Book STAC (4)	Less: Book Energy Cost Rate Revenue (5)	Base Revenue (6)=(3)-(4)-(5)	Proposed Base Revenue Prior to Roll-Out (7)	Roll-out of .7505¢/kWh Per D-21 (8)=1x.7505¢	Proposed Net Base Revenue Supp.No.15 (9)=(7)+(8)	$ Increase (10)=(9)-(6)	% Increase (11)=(10)/(6)
R	6,465,900	1,120,500	$769,638	$40,779	($10,608)	$739,467	$1,007,200	($48,527)	$958,673	$219,206	29.6%
RH	1,543,300	97,300	131,968	7,025	(2,481)	127,424	172,009	(11,582)	160,427	33,003	25.9
OP-Off Peak (WH)	393,600	102,250 (a)	26,686	1,433	(736)	25,989	28,943	(2,954)	25,989	0	0
POL	8,320	3,430 (a)	1,596	84	(15)	1,527	1,589	(62)	1,527	0	0
GS	3,406,780	120,027	357,866	18,957	(5,929)	344,838	472,610	(25,568)	447,042	102,204	29.6
PD(Incl Riders)	2,241,000	2,620	197,446	10,497	(4,061)	191,010	264,458	(16,818)	247,640	56,630	29.6
HT(Incl Riders)	12,696,300	2,316	885,276	47,318	(23,025)	860,983	1,211,355	(95,286)	1,116,069	255,086	29.6
EP-A	431,500	1	32,567	1,696	(807)	31,683	36,392	(3,238)	33,154	1,471	12.7 (b)
EP-S	268,500	2	20,780	1,151	(476)	20,100	25,103	(2,015)	23,088	2,988	14.9
SLP	104,148	2	15,654	823	(162)	14,993	15,775	(782)	14,993	0	0
SLS	60,840	535	19,007	995	(117)	18,129	18,586	(457)	18,129	0	0
TL	32,880	205	3,620	191	(57)	3,486	3,733	(247)	3,486	0	0
BLI	62	3	7	-	-	7	10	(1)	9	2	28.6
Trans Rent Rider	-	(a)	323	17	-	306	395	-	395	89	29.1
Total Electric	27,653,130	1,343,511	$2,462,434	$130,966	($48,474)	$2,379,942	$3,258,158	($207,537)	$3,050,621	$670,679	28.2%
Other Elec. Operations	513,200	2	65,859	-	-	65,859	65,859	-	65,859	-	-
Total Electric	28,166,330	1,343,513	$2,528,293	$130,966	($48,474)	$2,445,801	$3,324,017	($207,537)	$3,116,480	$670,679	27.4%
Plus: STAC in Excess of STAC Related Taxes (D-1)						4,959	4,959	-	4,959	-	-
Plus: Revenue from Growth Adjustment (D-3)						38,771	53,529	(3,677)	49,852	11,081	28.6
Plus: Interest on ECR Overcollections (D-4)						5,237	5,237	-	5,237	-	-
Plus: Non-Jurisdictional Rates Adjustment (D-19)						7,225	7,225	-	7,225	-	-
Total Revenue						$2,501,993	$3,394,967	($211,214)	$3,183,753	$681,760	27.2%

(a) Duplicate customers not included in total.
(b) Percentage shown is based on comparison of proposed revenue and revenue associated with actual load characteristics reflected in the March 1985 contract agreement. Refer to the Company's proof of revenue calculations, Interrogatory response IV-C-1, for the details supporting this percentage.

Philadelphia Electric Company - Combined Operations
BALANCE SHEET
June 30, 1986
(Thousand $)

ASSETS AND OTHER DEBITS	COMPANY
Utility Plant	
Electric	$8,743,664
Gas	485,914
Steam	54,098
Common	142,875
Construction Work in Progress	1,211,750
Total Utility Plant	$10,638,301
Less Provision for Depreciation	1,869,058
Net Utility Plant	$8,769,243
Nuclear Fuel	262,237
Property Under Capital Leases Incl. Nuclear Fuel	302,306
Net Utility Plant, incl. Nuclear Fuel	$9,333,786
Other Property and Investments	
Non-Utility Property	$13,016
Investments in Subsidiary Companies	132,814
Decommissioning Escrow Fund	15,279
Other Investments	1,000
Total	$162,109
Current and Accrued Assets	
Cash	$36,944
Temporary Cash Investments	32,250
Escrow Deposits	17,555
Special Deposits & Working Funds	9,765
Accounts Receivable	472,210
Materials and Supplies	151,928
Prepayments	79,834
Deferred Fuel Expense	(13,817)
Compensated Absences	43,316
Total	$829,985
Deferred Debits	
Unamortized Debt Expense	$13,137
Extraordinary Property Losses	6,687
Clearing Accounts	428
Miscellaneous Deferred Debits	73,410
Unamortized Loss on Reacquired Debt	12
Accumulated Deferred Income Taxes	28,811
Total	$122,485
TOTAL ASSETS AND OTHER DEBITS	$10,448,365

Philadelphia Electric Company - Combined Operations
BALANCE SHEET
June 30, 1986
(Thousand $)

LIABILITIES AND OTHER CREDITS	COMPANY	
Proprietary Capital		
Common Capital Stock	$2,641,663	
Preferred Capital Stock	926,182	
Premium on Preferred Stock	1,214	
Other Paid in Capital	6,091	
Retained Earnings	671,071	
Total	$4,246,221	
Long-Term Debt		
Bonds	$2,988,190	
Pollution Control Notes	518,185	
Other Long Term Debt	675,326	
Unamortized Net Discount on Long Term Debt	(17,176)	
Total	$4,164,525	
Current and Accrued Liabilities		
Short-Term Debt	$56,335	
Obligations Under Capital Leases	67,233	
Compensated Absences Payable	43,316	
Current Maturities of Long Term Debt	190,800	
Accounts Payable	136,862	
Customers' Deposits	7,873	(a)
Taxes Accrued	56,800	
Interest Accrued	110,557	
Dividends Declared	123,990	
Miscellaneous Current & Accrued Liabilities	24,391	
Deferred Income Taxes on Fuel	(7,818)	
Total	$810,339	
Deferred Credits		
Customers' Advances for Construction	$819	(b)
Accumulated Deferred Investment Tax Credits	346,613	
Other Deferred Credits	62,954	
Unamortized Gain on Reacquired Debt	7,816	
Obligation Under Capital Leases	235,073	
Accumulated Deferred Income Taxes		
Accelerated Amortization Property	2,323	
Other Property	569,092	
Other	2,590	
Total	$1,227,280	
TOTAL LIABILITIES AND OTHER CREDITS	$10,448,365	

(a) Electric Portion = $7,682
(b) Electric Portion = $434

Philadelphia Electric Company - Electric Operations

ELECTRIC PLANT
AT JUNE 30, 1986
(Thousand $)

Electric Plant In Service		
Intangible Plant		
302.	Franchises and Consents	$163
Production Plant		
Steam Production Plant		
310.	Land and Land Rights	5,211
311.	Structures and Improvements	214,089
312.	Boiler Plant Equipment	566,635
314.	Turbogenerator Units	168,960
315.	Accessory Electric Equipment	97,439
316.	Miscellaneous Power Plant Equipment	12,322
	Total Steam Production Plant	$1,064,656
Nuclear Production		
320.	Land and Land Rights	7,706
321.	Structures and Improvements	1,101,939
322.	Reactor Plant Equipment	2,645,837
323.	Turbogenerator Units	527,305
324.	Accessory Electric Equipment	739,907
325.	Miscellaneous Power Plant Equipment	243,088
	Total Nuclear Production Plant	$5,265,782
Hydraulic Production		
330.	Land and Land Rights	1,421
331.	Structures and Improvements	14,484
332.	Reservoirs, Dams and Waterways	34,955
333.	Water Wheels, Turbines and Generators	21,971
334.	Accessory Electric Equipment	8,662
335.	Miscellaneous Power Plant Equipment	2,039
336.	Roads, Railroads and Bridges	998
	Total Hydraulic Production Plant	$84,530
Other Production Plant		
340.	Land and Land Rights	846
341.	Structures and Improvements	4,218
342.	Fuel Holders, Producers and Accessories	21,321
343.	Prime Movers	-
344.	Generators	82,131
345.	Accessory Electric Equipment	12,552
346.	Miscellaneous Power Plant Equipment	2,266
	Total Other Production Plant	$123,334
Total Production Plant		$6,538,302

Philadelphia Electric Company - Electric Operations

ELECTRIC PLANT
AT JUNE 30, 1986
(Thousand $)

Electric Plant In Service (Continued)

Transmission Plant		
350.	Land and Land Rights	47,970
352.	Structures and Improvements	16,644
353.	Station Equipment	238,021
354.	Towers and Fixtures	184,125
355.	Poles and Fixtures	496
356.	Overhead Conductors and Devices	101,715
357.	Undergroumd Conduit	2,521
358.	Underground Conductors and Devices	43,090
359.	Roads and Trails	1,730
	Total Transmission Plant	$636,312
Distribution Plant		
360.	Land and Land Rights	22,510
361.	Structures and Improvements	35,372
362.	Station Equipment	300,311
364.	Poles, Towers and Fixtures	136,407
365.	Overhead Conductors and Devices	208,206
366.	Underground Conduit	148,663
367.	Underground Conductors and Devices	263,562
368.	Line Transformers	160,797
369.	Services	112,176
370.	Meters	96,450
371.	Installations on Customers' Premises	278
373.	Street Lighting and Signal Systems	28,087
	Total Distribution Plant	$1,512,819
General Plant		
389.	Land and Land Rights	1,967
390.	Structures and Improvements	19,149
391.	Office Furniture & Equipment	3,205
393.	Stores Equipment	404
394.	Tools, Shop and Garage Equipment	4,980
395.	Laboratory Equipment	7,480
397.	Communication Equipment	1,830
398.	Miscellaneous Equipment	2,263
	Sub-Total	$41,278
399.	Other Tangible Property Anti-trust Price Adjustment	(2,136)
	Total General Plant	$39,142
Total Electric Plant In Service (carried forward)		$8,726,738

Philadelphia Electric Company - Electric Operations

ELECTRIC PLANT
AT JUNE 30, 1986
(Thousand $)

Total Electric Plant In Service (brought forward)	$8,726,738
Construction Work in Progress	1,174,729
Plant Held for Future Use	
Land and Land Rights	16,905
Other Than Land and Land Rights	21
Total	$16,926
Total Electric Plant	$9,918,393

Philadelphia Electric Company - Electric Operations

COMMON UTILITY PLANT
AT JUNE 30, 1986
(Thousand $)

Intangible Plant		
301.	Organization	$677
General Plant		
389.	Land and Land Rights	3,115
390.	Structures and Improvements	94,170
391.	Office Furniture and Equipment	22,706
392.	Transportation Equipment	7,021
393.	Stores Equipment	2,028
394.	Tools, Shop and Garage Equipment	6,965
396.	Power Operated Equipment	1,422
397.	Communication Equipment	1,866
398.	Miscellaneous Equipment	2,517
	Total - General Plant	$141,810
Total Common Utility Plant in Service		$142,487
Construction Work in Progress		2,857
Plant Held for Future Use (Land and Land Rights)		388
Total Common Utility Plant		$145,732

Philadelphia Electric Company
BOOK ACCUMULATED PROVISION FOR DEPRECIATION
OF UTILITY PLANT IN SERVICE
INCLUDING DECOMMISSIONING EXPENSE
JUNE 30, 1986
(Thousand $)

Effective with the Commission Order at Docket R-842590 (January 25, 1985), the Company began to maintain book depreciation reserve information by detailed plant accounts for electric and common plant. The reserve by plant account for electric operations, including allocated common can be found in Exhibit AW-2.

Reserve for Depreciation - Electric (C-2)	$1,633,742
Decommissioning Reserve (D-15)	20,946
Total Electric Reserve	$1,654,688
Share of Common $51,600 (C-3)x 86.188% (B-17)	44,473
Total	$1,699,161

Philadelphia Electric Company and Subsidiary Companies

12 MONTHS ENDING JUNE 30, 1986
CONSOLIDATED STATEMENT OF INCOME
(Thousand $)

Operating Revenue	
Electric	$2,550,517
Gas	450,484
Steam	62,075
Total Operating Revenue	$3,063,076
Operating Expenses	
Total Operation and Maintenance	$1,908,141
Provision for Depreciation and Amortization	$183,924
Provision for Taxes	
Federal Income Taxes	124,434
State and Local Income Taxes	29,799
Investment Tax Credit Adjustments-Net	6,177
Deferred Income Taxes	105,879
Taxes Other Than Income	228,822
Total Provision for Taxes	495,111
Total Operating Expenses	$2,587,176
Operating Income	$475,900
Other Income	
Allowance for Other Funds Used During Construction	79,001
Other Income and Deductions	88,500
Income Taxes	147,008
Total Other Income	$314,509
Income Before Interest Charges	$790,409
Interest Charges	
Interest on Long-Term Debt	475,092
Other Interest	10,418
Allowance for Borrowed Funds - Credit	(284,551)
Net Interest Charges	$200,959
Net Income	589,450
Dividends on Preferred Stocks	95,437
Earnings Available for Common Stock	$494,013
Common Stock Outstanding	
End of Period (1000)	183,505
Average (1000)	176,248
Earnings per average share (dollars)	$2.803

Philadelphia Electric Company - Electric Operations
STATEMENT OF ELECTRIC OPERATING INCOME
12 Months Ending June 30, 1986
(Thousand $)

OPERATING REVENUE		
	Sales of Electricity:	
440	Residential	$928,292
442	Commercial & Industrial	1,442,184
444	Public Street and Highway Lighting	38,281
446	Sales to Railroads and Railways	53,347
447	Sales for Resale	23,085
448	Interdepartmental Sales	4,126
	Total Sales of Electricity	$2,489,315
	Other Operating Revenues:	
450	Forfeited Discounts	9,420
451	Miscellaneous Service Revenues	2,150
454	Rent from Electric Property	10,449
455	Interdepartmental Rents	4,423
456	Other Electric Revenues	12,536
	Total Other Operating Revenues	$38,978
	Total Electric Operating Revenues	$2,528,293
OPERATING EXPENSES		
401	Operation and Maintenance Expense:	
	Power Production	1,138,824
	Transmission	23,224
	Distribution	101,778
	Customer Accounts	80,738
	Customer Service & Information	10,463
	Sales	906
	Administrative and General Expense	146,770
	Total Operation and Maintenance Expense	$1,502,703
403	Depreciation Expense	163,391
405	Amortization of Other Electric Plant	(641)
407	Amortization of Property Losses	1,679
	Taxes	
408.1	Taxes Other Than Income Taxes	$199,837
409.1	Income Taxes	132,673
410.1	Provisions for Deferred Income Taxes	107,815
411.1	Inc. Taxes Deferred - Other	(14,033)
411.4	Investment Tax Credit Adjustments	6,912
	Total Taxes	$433,204
411.6&7	Gain or Loss from Disposition of Utility Plant	-
	Total Operating Expenses	$2,100,336
	Operating Income	$427,957

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
12 Months Ending JUNE 30, 1986
(Thousand $)

I. POWER PRODUCTION EXPENSES

STEAM POWER GENERATION

OPERATION		
500	Operation Supervision	15,217
501	Fuel	269,280
502	Steam Expenses	38,124
504	Steam Transferred - Credit	(46,600)
505	Electric Expenses	7,682
506	Miscellaneous Steam Power Expenses	13,356
507	Rents	15,065
	Total Operation	$312,124
MAINTENANCE		
510	Maintenance Supervision and Engineering	9,599
511	Maintenance of Structures	9,042
512	Maintenance of Boiler Plant	64,728
513	Maintenance of Electric Plant	18,284
514	Maintenance of Miscellaneous Steam Plant	3,552
	Total Maintenance	$105,205
	Total Power Production Expenses-Steam Power	$417,329

NUCLEAR POWER GENERATION

OPERATION		
517	Operation Supervision and Engineering	12,727
518	Fuel	136,823 (a)
519	Coolants and Water	1,138
520	Steam Expenses	18,798
523	Electric Expenses	2,356
524	Miscellaneous Nuclear Power Expenses	39,955
525	Rents	87
	Total Operation	$211,884
MAINTENANCE		
528	Maintenance Supervision and Engineering	16,795
529	Maintenance of Structures	3,715
530	Maintenance of Reactor Plant Equipment	16,884
531	Maintenance of Electric Plant	10,049
532	Maintenance of Miscellaneous Nuclear Plant	5,448
	Total Maintenance	$52,891
	Total Power Production Expenses-Nuclear Power	$264,775

(a) Includes $11,715 for spent nuclear fuel disposal expense; $26,985 for Limerick fuel costs from January 1, 1986 through June 30, 1986.

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
12 Months Ending JUNE 30, 1986
(Thousand $)

	HYDRAULIC POWER GENERATION	
OPERATION		
535	Operation Supervision and Engineering	$404
536	Water and Power	368
537	Hydraulic Expenses	1,170
538	Electric Expenses	230
539	Miscellaneous Hydraulic Power Generation Expenses	424
540	Rents	1
	Total Operation	$2,597
MAINTENANCE		
541	Maintenance Supervision and Engineering	540
542	Maintenance of Structures	210
543	Maintenance of Reservoirs, Dams & Waterways	247
544	Maintenance of Electric Plant	3,133
545	Maintenance of Miscellaneous Hydraulic Plant	147
	Total Maintenance	$4,277
	Total Power Production Expenses-Hydraulic Power	$6,874
	OTHER POWER GENERATION	
OPERATION		
546	Operation Supervision and Engineering	1,029
547	Fuel	10,192
548	Generation Expenses	1,327
549	Miscellaneous Other Power Generation Expenses	1,479
550	Rents	1,140
	Total Operation	$15,167
MAINTENANCE		
551	Maintenance Supervision and Engineering	629
552	Maintenance of Structures	233
553	Maintenance of Generating and Electric Plant	6,221
554	Maintenance of Miscellaneous Other Power	102
	Total Maintenance	$7,185
	Total Power Production Expenses - Other Power	$22,352
	OTHER POWER SUPPLY EXPENSES	
555	Purchased Power	116,213
556	System Control and Load Dispatching	6,022
557	Other Expenses	305,259 (a)
	Total Other Power Supply Expenses	$427,494
	Total Power Production Expenses	$1,138,824

(a) Includes $218,208 of Deferred Fuel; $43 for Limerick precommercial generation in July 1985; $86,978 for the value of Limerick #1 generation from 8/1/85 through 12/31/85.

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
12 Months Ending JUNE 30, 1986
(Thousand $)

TRANSMISSION EXPENSES

OPERATION		
560	Operation Supervision and Engineering	2,264
561	Load Dispatching	1,601
562	Station Expenses	1,767
563	Overhead Line Expenses	221
564	Underground Line Expenses	247
566	Miscellaneous Transmission Expenses	1,296
567	Rents	6,722
	Total Operation	$14,118
MAINTENANCE		
568	Maintenance Supervision and Engineering	879
569	Maintenance of Structures	333
570	Maintenance of Station Equipment	5,112
571	Maintenance of Overhead Lines	2,146
572	Maintenance of Underground Lines	636
573	Maintenance of Miscellaneous Transmission Plant	-
	Total Maintenance	$9,106
	Total Transmission Expenses	$23,224

DISTRIBUTION EXPENSES

OPERATION		
580	Operation Supervision and Engineering	7,902
581	Load Dispatching	1,821
582	Station Expenses	5,461
583	Overhead Line Expenses	6,416
584	Underground Line Expenses	2,975
585	Street Lighting and Signal System Expenses	674
586	Meter Expenses	4,654
587	Customer Installation Expenses	4,868
588	Miscellaneous Distribution Expenses	11,240
589	Rents	3,973
	Total Operation	$49,984
MAINTENANCE		
590	Maintenance Supervision and Engineering	3,854
591	Maintenance of Structures	957
592	Maintenance of Station Equipment	7,794
593	Maintenance of Overhead Lines	23,354
594	Maintenance of Underground Lines	10,107
595	Maintenance of Line Transformers	1,720
596	Maintenance of Street Lighting and Signal System	1,113
597	Maintenance of Meters	1,687
598	Maintenance of Miscellaneous Distribution Plant	1,208
	Total Maintenance	$51,794
	Total Distribution Expenses	$101,778

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
(Thousand $)
12 Months Ending June 30, 1986

	IV CUSTOMER ACCOUNTS EXPENSES	
OPERATION		
901	Supervision	2,540
902	Meter Reading Expenses	14,215
903	Customer Records and Collection	46,975
904	Uncollectible Accounts	16,472
905	Miscellaneous Customer Accounts Expenses	536
	Total Customer Accounts Expenses	$80,738
	V CUSTOMER SERVICE & INFORMATIONAL EXPENSES	
OPERATION		
907	Supervision	1,044
908	Customer Assistance Expenses	6,299
909	Informational & Instructional Advertising Expenses	2,768
910	Misc. Cust. Serv. & Information Expenses	352
	Total Cust. Serv. & Information Expenses	$10,463
	VI SALES EXPENSES	
OPERATION		
911	Supervision	128
912	Demonstrating and Selling Expenses	360
913	Advertising Expenses	340
916	Miscellaneous Sales Expenses	78
	Total Sales Expenses	$906
	VII ADMINISTRATIVE AND GENERAL EXPENSES	
OPERATION		
920	Administrative and General Salaries	37,754
921	Office Supplies and Expenses	15,894
923	Outside Services Employed	4,859
924	Property Insurance	9,550
925	Injuries and Damages	8,475
926	Employee Pensions and Benefits	48,285
928	Regulatory Commission Expenses	4,353
929	Duplicate Charges - Credit	(1,800)
930	General Advertising and Miscellaneous	17,793
	Total Operation	$145,163
MAINTENANCE		
935	Maintenance of General Plant	1,607
	Total Administrative and General Expenses	146,770
	VIII TOTAL OPERATION AND MAINTENANCE EXP. (B-9)	$1,502,703
	IX DEPRECIATION AND AMORTIZATION	
940	Depreciation	163,391 (a)
943	Amortization of Other Electric Plant	(641)
944	Amortization of Property Losses	1,679
	Total Depreciation and Amortization	$164,429

(a) Includes $4,190 of nuclear decommissioning accruals.

Philadelphia Electric Company - Electric Operations
OPERATING EXPENSES
12 Months Ending June 30, 1986
(Thousand $)

X TAXES

TAXES OTHER THAN INCOME TAXES

State and Local	
Capital Stock - Pennsylvania	25,793
Capital Stock - New Jersey	92
Gross Receipts	110,055
Real Estate - Local	807
Real Estate - State	42,432
State Unemployment Compensation	1,362
Philadelphia Realty Occupancy	451
Other State and Local	582
Total State and Local	$181,574
Federal	
Telephone and Telegraph	25
Federal Unemployment Compensation	778
Federal Old Age Benefits	17,491
Other	(31)
Total Federal	$18,263
Total Taxes Other Than Income	$199,837

INCOME TAXES

State - Pennsylvania	25,654
State - Maryland	122
State - New Jersey	1,124
Federal	105,773
Total Income Taxes	$132,673
Provisions for Deferred Income Taxes	107,815
Income Taxes Deferred - Other	(14,033)
Investment Tax Credit Adjustments*	6,912
TOTAL ALL TAXES	$433,204
XII TOTAL OPERATING EXPENSES (B-9)	$2,100,336

*Investment tax credit of $17,618 less amortization of $10,706