PFMA Statement 1 w/ Ex. C

2-19-86

Phila, PA

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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SECRETARY'S OFFIC
Public Utility Commiss

Pennsylvania Public Utility Commission	:	
-vs-	:	R-850152
Philadelphia Electric Company	:	

PREPARED TESTIMONY AND EXHIBIT

OF

CHARLES A. LARSON

On Behalf of

THE PENNSYLVANIA FOOD MERCHANTS ASSOCIATION

DOCKETED

FEB 26 1986

January 22, 1986

CONSULTING SERVICES, INC.
1776 Massachusetts Avenue, NW
Washington, DC 20036
(202) 775-8418

DOCUMENT
FOLDER

DIRECT TESTIMONY OF CHARLES A. LARSON
ON BEHALF OF THE PENNSYLVANIA FOOD MERCHANTS ASSOCIATION
DOCKET NO. R-850152

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

A. My name is Charles A. Larson. I am President of Consulting Services Inc., a firm of economic and engineering consultants. My office is at 1776 Massachusetts Avenue, N.W., Washington, D.C., 20036.

Q. What are your educational qualifications?

A. I received the degree of Bachelor of Science in Electrical Engineering in 1948 from the University of Wisconsin. In 1950, I received a Master's Degree in Business Administration, in Public Utility Economics and Transportation, from the University of Wisconsin's Graduate School of Business. I studied accounting at the University of Denver's Graduate School of Business. At the Graduate School of Business of New York University, I completed my residence requirements for a doctorate degree in economics, statistics and finance.

Q. Are you a member of any professional associations?

A. I am a member of the following professional associations:

American Association of Cost Engineers (Certified Cost Engineer)

Institute of Electrical and Electronic Engineers

National Association of Accountants

Financial Management Association

Society of Petroleum Engineers

Also, I have served as a member of the Edison Electric Institute's Rate Research Committee, American Gas Association's Rate Committee, and the Rate Committee of the International District Heating Association.

Q. What was your first work experience?

A. During World War II, I was a Naval Officer assigned to air intelligence with a research and development task force.

Q. What was your first engineering experience?

A. Starting in 1947, I was a system study engineer with the Wisconsin Electric Cooperative in Madison, Wisconsin. My economic-engineering duties were to make economic feasibility studies of rural electric distribution systems in Western and Northern Wisconsin.

Q. What was your first management consulting experience?

A. In 1950, I became the Assistant Rate Engineer with the firm of Middle West Service Company in Chicago, Illinois. This firm was engaged in management and engineering consultation to gas and electric utility companies.

Q. What were your responsibilities in that firm?

A. My responsibilities were primarily directed to the preparation of financial, rate, and cost analyses. In this capacity, I prepared financial statements, made economic forecasts, designed rates, determined costs of service and allocated costs for numerous gas and electric utilities.

Q. Have you had experience in the operation and management of a utility company?

A. Yes. In 1954, I became a rate analyst with Public Service Company of Colorado in Denver, Colorado. This firm is a combination utility which provides gas and electric service in various counties of Colorado, steam service in the City and County of Denver and bus service in the City of Boulder. I worked in the Department of Rates, Real Estate and Property Accounting in the Accounting Division. My responsibilities included: (1) analysis of financial statements; (2) preparation of costs of service; (3) rate design; (4) supervision of gathering of rate statistics; and (5) review of customer contracts and rules and regulations for gas, electric, steam, and bus customers.

Q. Have you had any experience as an economist?

A. Yes. During 1957-1959, I was an economist for the Edison Electric Institute in New York City. EEI is a trade association for the electric utility companies.

Q. What were your responsibilities with EEI?

A. I was responsible for economic studies of the electric utility industry related to forecasting, taxes, executive compensation, and energy competition. I represented the staff at meetings of the Rate Research Committee.

Q. Have you had additional experience as an economist?

A. Yes. For nearly 10 years, I was a senior consultant with National Economic Research Associates, Inc., a firm of consulting economists in New York City.

Q. What were your responsibilities with that firm?

A. I was responsible, primarily, for analyzing the cost of finding, producing, gathering, processing, transporting and distributing natural gas. Additionally, I made financial studies of large integrated oil companies.

Q. Have you had other consulting experience?

A. Yes. I was Vice-President and Director of the Regulatory Division of Commonwealth Management Consultants in Washington, D.C. from 1968 to 1972.

Q. What were your responsibilities at Commonwealth?

A. I directed projects and studies of regulated companies, including cost and rate analyses of electric and gas utilities, rate of return determination, estimates of depreciation rates, valuations, competition, marketing, and forecasting of the demand and supply of energy. On numerous occasions I testified before regulatory agencies.

Q. Have you had additional consulting experience?

A. Yes. For nearly 10 years I was with H. Zinder and Associates, a firm of economic and engineering consultants in Washington, D.C.

Q. What was your position at Zinder?

A. I was a senior vice president and a member of the Board of Directors.

Q. What were your primary responsibilities at Zinder?

A. I prepared numerous cost and rate analyses, rate of return studies, depreciation estimates, and market studies for electric utilities, gas distributors, and gas pipelines.

Q. Have you testified before the Federal Energy Regulatory Commission?

A. Yes. I have appeared as a witness on numerous occasions before that Commission.

Q. Have you testified before state regulatory commissions?

A. Yes. I have testified before regulatory commissions in the following states: Alaska, Arizona, Connecticut, Delaware, District of Columbia, Florida, Indiana, Iowa, Kentucky, Massachusetts, Michigan, Missouri, New Hampshire, New Jersey, New Mexico, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, Texas, Utah, Vermont, Virginia, and West Virginia.

Q. Have you testified before Canadian Boards?

A. Yes. I have testified before the National Energy Board, the Alberta Public Utilities Board, the Ontario Energy Board, and the British Columbia Energy Commission.

Q. Have you testified before courts?

A. Yes, I have testified on valuation matters before three federal district courts, three lower courts and a state tax evaluation board.

Q. Please summarize your experience as an electric rate consultant.

A. I have been an electric rate consultant for over 35 years during which time I have prepared hundreds of cost allocation studies and have designed thousands of electric utility rates.

Q. Mr. Larson, what is the purpose of your testimony?

A. I have been asked by the representatives of the Pennsylvania Food Merchants Association (PFMA) to: (1) review the rate

increase filing of Philadelphia Electric Company (PECO), (2) comment on PECO's proposed rates which impact on the PFMA, and (3) make rate design recommendations for cost-based pricing consistent with the Public Utility Regulatory Policies Act (PURPA) as approved by this Commission.

A. Mr. Larson, would you summarize your findings from your review of PECO's filing?

Q. Yes. PECO's proposed rate design in these proceedings reflects a positive and significant advance towards the elimination of discrimination among the various rate classifications. As I will demonstrate, there has been gross discrimination against the general service secondary and the general service primary classes going back 12 or more years. However, the proposed rates in these proceedings are designed to limit the over-contribution for the general service secondary class to 116 per cent of the company's overall rate of return which is in contrast to the 140 per cent proposal of PECO in its last case (R-842590). Although the PFMA had hoped that closure would take place at a more rapid pace, so that unity could be achieved in these proceedings, the progress made by PECO's filing is gratifying and represents a significant step towards having cost-based rates.

Q. Why should rates follow costs?

A. It is a generally accepted principle that rates which follow costs are efficient, equitable and provide the most desirable level of energy conservation. These principles were adopted by this Commission when it reviewed the rate standards set

forth in PURPA. Under the PURPA standards, the rate of return for each individual class should follow the Company's overall rate of return. If the rates discriminate against certain classes, that discrimination should be eliminated.

Q. What are the benefits of cost-based pricing?

A. When a rate follows costs, customers only pay for what it costs to make and sell the energy used, no more, no less. Cost-based rates limit the consumption of energy, especially on-peak energy, to the amount needed by customers to maintain their level of operations and/or living comforts without the waste of energy caused by cross-subsidization. The beneficial effects of cost-based rates apply throughout the range of use as well as within and among customer class.

Q. What role do rate features, such as hours' use and night riders, play in the achievement of the cost objectives?

A. Rate features, such as hours' use and night riders, are steps toward achieving the goal of designing rates to follow costs throughout the range of use. The time-of-use rate will encourage customers to adjust their consumption to minimize their energy usage during peak periods consistent with acceptable changes in their life styles and business practices.

Q. Should each class earn for PECO the system average rate of return?

A. Yes. Each class of service should, over time, earn for PECO the system average rate of return in fairness to all customers and in order to promote the highest level of productivity for PECO. While small year to year variances do not effect rate

fairness, long periods of extreme variance in rate of return, as contained in PECO's previous filings, cannot be supported.

Q. Can you describe the historical discrimination to which you refer?

A. Yes. As shown on Page 1 of my exhibit, there has been continuous rate discrimination against the General Service (GS) and Primary Distribution (PD) customer classes over the last 12 years on a consistent cost basis. Since 1974, the proposed unitized or relative rates of return for the GS class range from a high of 150.5 percent in 1982 to a low of 136.5 percent in 1977. For the PD class, the proposed unitized rates of return range from a high of 140.3 percent in 1984 to a low of 118.8 percent in 1980. Not until this case, has PECO proposed a unity rate of return for Rate PD.

Q. Are you aware of any justification for this historical rate discrimination?

A. No. In the short run, rates of return might vary from the system average due to a gradual correction of an inequitable rate or because of minor cost/revenue imbalances which will move the class rate of return slightly above or below average from time to time. However, there should be no policy of deliberate subsidization and there is no justification for this prolonged discrimination.

Q. Has the Commission attempted to bring PECO's class rates of return closer to the Company's overall rate of return?

A. Yes. There has been a deliberate move by the PUC to stop this discriminatory trend and reach the PURPA standard of

cost-based rates within a reasonable period of time. Four years ago, in Case No. 1626, overcontributions were limited to 140 percent of system average. Three years ago, in Case No. 2291, the Commission ordered a cap of 130 percent. This policy of gradually eliminating discrimination and cross-subsidization should be continued.

Q. Mr. Larson, do you propose any modifications in the cost allocation methodology utilized by PECO in this proceeding?

A. No. PECO's cost allocation study by class of service that has been submitted in this case follows generally accepted cost allocation procedures, employs reliable and extensive load research data and has been prepared in a consistent manner for many years. For those reasons, I have accepted that methodology for purposes of my testimony in this case.

Q. Do you recommend any changes to PECO's proposed rate design?

A. Yes. I recommend two changes. First, the end blocks, especially in Rate GS, should be designed lower to reflect the cost of producing electric energy during off-peak periods. Second, there should be a time-of-use adjustment available to Rates GS and PD customers as it is presently available to Rate HT customers.

Q. You stated that one of your recommended changes to PECO's proposed rates would be to lower the end rates. What are those end rates?

A. The end rates are the rates for off-peak usage. For Rate GS, the end rate applies to KWH usage beyond 400 hours' use of demand. For Rate PD, the end rate applies to KWH usage beyond

300 hours' use of demand. In other words, the end rates are for usage greater than 41 and 55 per cent load factor for Rate PD and GS, respectively. On-peak usage stops at about 31 per cent load factor based on prescribed on-peak hours of 8 a.m. to 8 p.m. Monday through Thursday and 8 a.m. to 4 p.m. on Friday, except holidays.

Page 2 of my exhibit shows the end rates for Rates GS and PD for the present rates and the proposed rates. The end rate for Rate GS is presently 5.89¢ per KWH and as proposed is 5.14¢ per KWH reflecting the approximately 7-mill decrease in fuel costs resulting from the start up of Limerick Unit No. 1.

For Rate PD, the present end rate is 3.98¢ per KWH. The proposed end rate is 3.83¢ per KWH. For Rate PD, the 7-mill decrease in base fuel costs has been approximately offset by the increase in the end rate.

The difference in end rates between Rates GS and PD is 1.91¢ per KWH in the present rates which has been reduced to 1.31¢ per KWH in PECO's proposed rates. In my judgement, the 1.31-cent differential can not be cost justified since the only material cost difference is that of serving primary customers versus serving secondary customers. This cost differential is approximately 3 mills. Accordingly, my recommendation is that the Rate GS end rate be set at 3 mills above that for Rate PD.

Q. What end block do you recommend for Rate PD?

A. At this time I have not completed my analysis of the cost support for an end rate for Rate PD. However, based on the

information on costs from the previous case and recognizing that the new Limerick Unit No. 1 will reduce average fuel costs by approximately 7 mills per KWH, it is my recommendation that the end block for Rate PD be set at no higher than 3¢ per KWH with a 3 mill differential between Rates PD and GS. Thus, the end block for Rate GS should not be more than 3.3¢ per KWH. These end rates recognize the principle of gradualism in reducing the rates to the level of off-peak fuel costs of about 1.8 cents per KWH plus an incentive margin of 1.2 cents per KWH.

Q. What is PECO's basis for pricing these end blocks at rates well above the off-peak fuel costs?

A. PECO's rate design theory as testified by Messrs. Williams and Sundermeir is to apply the Bary Curve to the demand cost units from the cost allocation study throughout the range of use. Although I agree that this approach is proper throughout most of the range of use, at higher load factors, over 300 or 400 hours' use of demand, usage is, for the most part, off-peak and should be priced to reflect such off-peak costs. PECO's pricing of the end rate includes the recovery of some on-peak fixed costs which were never incurred by these high load factor off-peak customers.

Q. Does the Bary Curve show the relationship between the coincident factor and the load factor throughout the range of use?

A. Yes. The Bary Curve shows the relationship between the coincident factor and the load factor between zero and 100 per cent load factor. However, two observations are important,

information on costs from the previous case and recognizing that the new Limerick Unit No. 1 will reduce average fuel costs by approximately 7 mills per KWH, it is my recommendation that the end block for Rate PD be set at no higher than 3¢ per KWH with a 3 mill differential between Rates PD and GS. Thus, the end block for Rate GS should not be more than 3.3¢ per KWH. These end rates recognize the principle of gradualism in reducing the rates to the level of off-peak fuel costs of about 1.8 cents per KWH plus an incentive margin of 1.2 cents per KWH.

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Q. Does the Bary Curve show the relationship between the coincident factor and the load factor throughout the range of use?

A. Yes. The Bary Curve shows the relationship between the coincident factor and the load factor between zero and 100 per cent load factor. However, two observations are important,

namely, (1) the Bary Curve is largely flat at about 80 per cent coincidence through most of the practical range of usage, and (2) with reference to off-peak usage assuming on-peak demand, the load factors can greatly exceed 100 per cent. Accordingly, the Bary Curve is not applicable to load factors in the higher ranges nor to off-peak usage for two reasons. First, little or no empirical information is known about customers in the high load factor range and that information which is available is usually not based on on-peak system demand. Second, the Bary Curve was never designed to reflect cost relationships for off-peak service.

Q. You mentioned that the marginal cost of operating the new Limerick Unit is about one cent per KWH. How does that cost compare with the average price paid by customers on Rate PD?

A. The average price paid by customers on Rate PD is 11 cents per KWH, whereas the cost of producing an additional KWH off-peak by Limerick Unit 1 is only one cent per KWH as shown on Page 3 of my exhibit.

Q. Mr. Larson, your second rate design recommendation was that the time-of-use adjustment should be extended to Rate GS and Rate PD. Is there some relationship between your first and second recommendations?

A. Yes. If ultimately PECO switches to a time-of-use rate, obviously there would be no need for a time-of-use adjustment. Also, if end rates are eventually designed to reflect off-peak fuel costs plus a modest margin, there would be less need for a time-of-use adjustment rider.

At this time, PECO has neither a time-of-use rate nor cost-based end rates. Accordingly, at this time, I recommend that the time-of-use adjustment in Rate HT be extended to Rate GS and Rate PD.

Q. Does this complete your testimony?

A. Yes.

PHILADELPHIA ELECTRIC COMPANY

Unitized Rates of Return 1/ by Proposed Rates PD and GS

Line No.	(1) Case Docket No.	(2) Test Ending Year	(3) Unitized Rate of Return 2/ Rate PD	(4) Unitized Rate of Return 2/ Rate GS
1	0152	6/86	97.6% 3/	115.7% 3/
2	2590	12/84	140.3	140.1
3	2291	10/83	132.4	140.3
4	1626	3/82	129.4	150.5
5	1225	3/81	125.0	147.5
6	865	3/80	118.8	146.7
7	438	12/77	119.3	136.5
8	295	12/74	120.4	148.5

1/ Class rate of return divided by total company rate of return.
2/ Exhibit 9 in Docket R-842590, Schedule 1, except for 1986 (Line 1).
3/ Exhibit WFS-1, Page 6a, Line 33.

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PHILADELPHIA ELECTRIC COMPANY

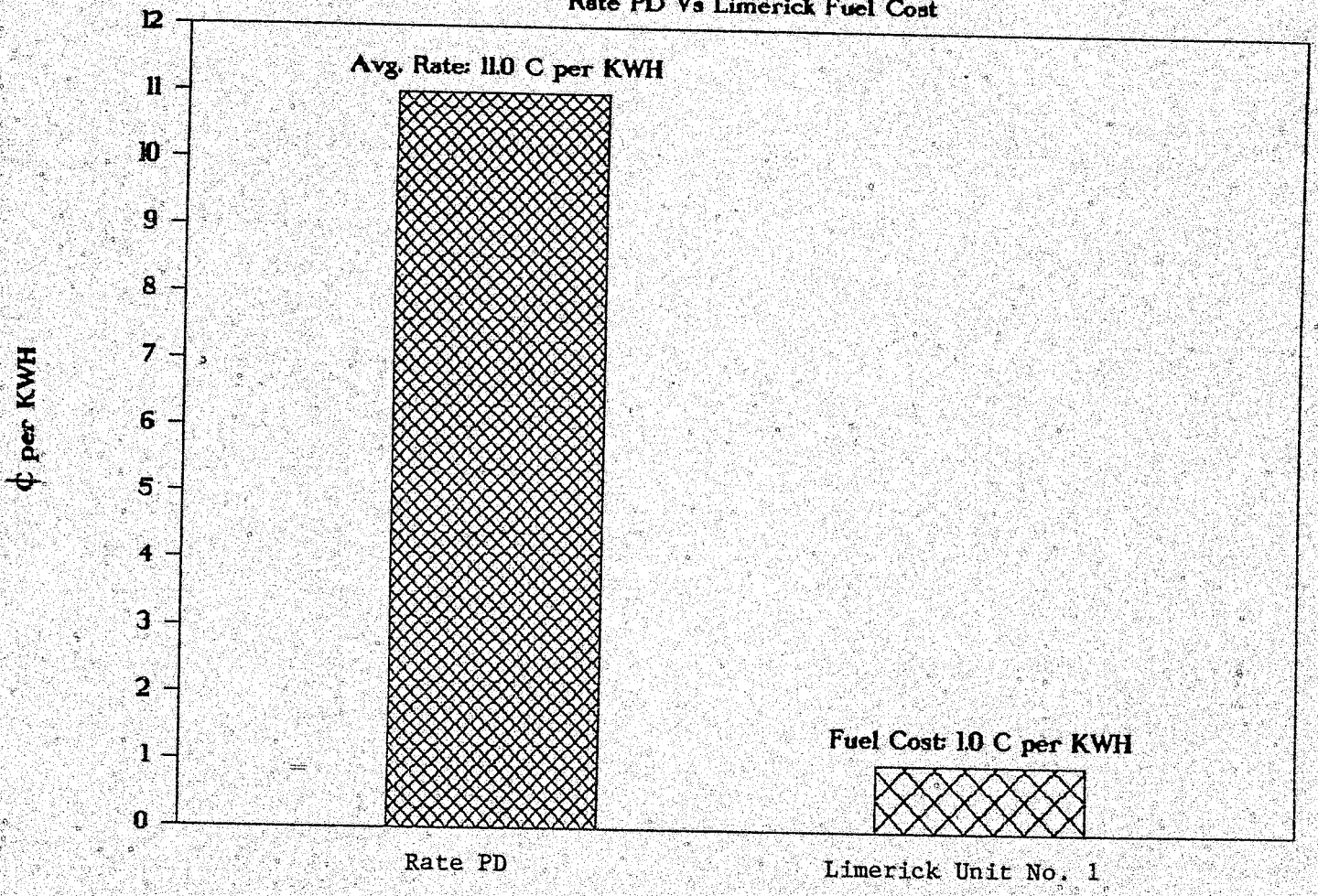
Comparison of End Rates
Rates GS and PD

Line No.	(1) Rate	(2) Base End Rates Present Rate 1/	(3) Base End Rates Proposed Rate 2/
		¢ per KWH	
1	GS	5.89¢	5.14¢
2	PD	3.98¢	3.83¢
3	Difference	1.91¢	1.31¢

1/ Supplement No. 11.
2/ Supplement No. 15.

Philadelphia Electric Company

Rate PD Vs Limerick Fuel Cost



2-19-86

Phila PD

PDS

Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission

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FEB24 1986

SECRETARY'S OFFICE
Public Utility Commission

Pennsylvania Public Utility Commission, et al.

vs.

Philadelphia Electric Company

PA P.U.C. Docket No. R-850152

DOCKETED

FEB 26 1986

Direct Testimony

of the

Pennsylvania Business Utility Users Group

Witness: Charles W. King

FOLDER

Filed: January 22, 1986

TESTIMONY OF CHARLES W. KING

Introduction

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

A. My name is Charles W. King. I am Vice President of the economic consulting firm of Snavely, King & Associates, Inc., with offices at 1220 L Street, N.W., Washington, D.C. 20005.

Q. Will you briefly describe Snavely, King & Associates, Inc.?

A. Snavely, King & Associates, Inc. was formed in April 1970 to conduct research on a consulting basis into economic issues of costs, revenues, rates, and demand characteristics of regulated industries. Most of the firm's work has involved the preparation and presentation of expert testimony before Federal and state regulatory agencies.

Q. Have you attached a summary of your qualifications and experience to this testimony?

A. Yes. Attachment A is a brief summary of my qualifications and experience. Attachment B is a tabulation of my appearances before Federal and state regulatory agencies in connection with utility rate proceedings.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Pennsylvania Business Utility Users Group, which is an informal association of leading general merchandise retail store chains in the Philadelphia area.

Q. What issues will your testimony address?

A. My testimony will address two issues. The first is the lack of need by the Philadelphia Electric Company (PECO) for a major "rate shock" increase at this time to cover the capital and operating costs of the Limerick 1 nuclear generating unit. I will suggest three alternative

procedures by which PECO could be compensated fully for the costs of Limerick without a major rate increase.

The second issue is the appropriate allocation of the Limerick 1 investment to customer classes and to the rate elements within the respective class tariff schedules.

I. LIMERICK RATE INCREASE

Q. Please describe the rate increase that PECO is proposing in this proceeding?

A. PECO is proposing an overall rate increase of $670.7 million, or 28.2 percent, virtually all related to the addition of the Limerick 1 nuclear generating unit to the Company's rate base. This $670.7 million increase, however, is net of fuel savings of $207.5 million, which will occur only if the unit performs at a target capacity factor during its initial year of operation. If the plant fails to perform up to this expectation, the actual rate increase imposed on PECO's customers could be as great as $878 million, or 37 percent.[1/]

In recognition of the enormity of this rate increase, PECO is proposing a phase-in plan whereby rates would be increased 9.4 percent during each of the first three years. During the subsequent four years, ratepayers would be obliged to refund PECO's underrecovery from the initial three years of the phase-in program. Assuming PECO were awarded all of the revenue it is seeking, the effect of its phase-in program would be to convert a 28.2 percent one-year rate increase into a 39.3 percent four-year increase.

[1/] PECO Exhibit TPH-2, p. A-5.

Q. Is this rate increase desirable?

A. No, it is not. The rate increase proposed by PECO would create a "rate shock" that would severely burden residents of the Philadelphia area, weaken the businesses and the government agencies that serve those residents, and damage many of the industries that represent the employment base of the area. In my opinion, the rate increase proposed by the Company would even damage PECO itself. In addition, the proposed increase, with or without phasing, would be extremely discriminatory among the generations of ratepayers who will be served by the Limerick plant. Finally, and probably most importantly, a rate increase of the magnitude proposed by PECO is totally unnecessary.

Q. In what way does PECO's proposed rate increase burden the residents of the Philadelphia area?

A. PECO's rate proposal represents a severe increase in the cost of a basic service critical to the maintenance of a minimal standard of living. Electric rate increases are highly regressive; that is, they burden the poor much more severely than the rich because the poor spend a greater proportion of their income on electric service than do the rich.

Q. How would PECO's rate increase weaken the businesses and governments that serve Philadelphia area residents?

A. The direct effect of PECO's proposed rates would be to increase the electric charges paid by those private and public entities that serve Philadelphia area residents. Some of these entities may be able to pass the increase through in the form of higher prices, charges or taxes, producing a "double whammy" effect on area residents. Other entities, such

as general service merchandise retail stores, will probably not be able to pass through these increases because they must compete with mail order catalogue merchandising and with retailers outside of the PECO service area.

In addition to the direct cost of the PECO increase, service industries and governments suffer from the syphoning off of disposable income that could otherwise be spent for consumer goods or used to support public services. In this manner, PECO's proposed increase would weaken the entire commercial and government infrastructure of the Philadelphia area.

Q. How would PECO's proposed rate increase damage the base employment industries of the Philadelphia area?

A. Most, if not all, of the economic base industries in the Philadelphia area compete with suppliers or manufacturers of similar goods and services elsewhere in the nation and in the world. To the extent that increases and electric charges increase their costs, their ability to compete is marginally degraded.

In past years, when all electric rates were increasing across the country, the competitive damage of a rate increase in Philadelphia was largely neutralized by the increases simultaneously occurring in most other areas. At the present time, however, electric rate increases elsewhere in the nation have diminished, as demonstrated by the following indices of commercial electric rates compiled by the Bureau of Labor Statistics.

Year	Index	Change from Previous Year 1/
1978	218.3	
1979	245.1	12.3%
1980	287.4	17.3
1981	325.6	13.3
1982	340.9	4.7
1983	348.7	2.3
1984	365.6	4.8
1985	371.4	1.6

With electric rates stable elsewhere in the country, PECO's 30 to 40 percent increase could severely undermine the competitive position of any Philadelphia area industry that is heavily reliant on electricity.

Q. Why do you believe the proposed increase could damage PECO itself?

A. There are two damaging effects on PECO, one economic, the other regulatory. The economic effect relates to the elasticity of demand for PECO's power. At one time it was thought that the demand for electricity was highly price inelastic because electricity is such a necessary service. With the dramatic inflation of electric rates during the period 1974 through 1981, it was found that electric demand is substantially more elastic than previously supposed. To the extent that the rate increase proposed by PECO reduces the consumption of electricity, it undermines the very justification for the construction of the Limerick plant, which was to serve the growing needs for electricity in the Philadelphia area. Correspondingly, the proposed increase would erode the revenue base which could support the plant once it is in service.

1/ Department of Labor, Bureau of Labor Statistics.

The regulatory effect relates to the pressure on this Commission to reduce or disallow the costs that the Company has incurred in building the Limerick unit. If the Limerick plant involved little or no increase in PECO's rates, the prudency of its construction costs would probably not be challenged, at least not severely. But with a 30 to 40 percent rate increase, Limerick appears a highly questionable investment, and the likelihood of substantial disallowances increases accordingly. As long as PECO continues to insist on conventional rate base treatment of Limerick, it greatly increases the probability that it will be denied full return on much of its investment and may even be denied recovery of some of that investment.

Q. Why is the proposed increase discriminatory among the generations of ratepayers that will be served by the Limerick plant?

A. PECO proposes to load the greatest portion of Limerick's capital costs into the initial years of the plant's service life. PECO's life cycle studies show that the 1986 capital-related costs -- depreciation, return and income taxes -- will be $747.27 million. By 1995, these costs will drop to $511.44 million, and by the turn of the century they will be down to $468.59 million. These costs, of course, are expressed in nominal, or current, dollars. At PECO's forecast 6 percent inflation rate, the constant dollar capital costs imposed on ratepayers will be $747.27 million in 1986, $292 million in 1995 and only $200 million in the year 2000. The phase-in plan does little to ameliorate this front-loading of capital costs. While it reduces the 1986 revenue requirement by $431 million, it increases the 1989 revenue requirement by something on the order of $225 million. Thus, PECO's

phase-in plan defers the heaviest burden of Limerick by three years. The plant is designed to operate for 39 years.

In contrast to these front-loaded costs, the benefits of Limerick are backloaded, that is, they tend to increase as the plant ages. The greatest benefit from Limerick will be the savings in the fossil fuels that would otherwise have beeen consumed if Limerick had not been built. The cost of these fossil fuels can be expected to increase with inflation. PECO's life cycle studies forecast that in 1986, Limerick's initial year, fuel savings will be only $150.82 million. By 1995, fuel savings will increase to the range of $900 million. By the year 2010, fuel savings may be as much as $3 billion. Limerick will also permit PECO to avoid constructing alternative generation facilities or buying capacity from other generating entities. Again, the effect of inflation will cause this benefit to increase over the years, from an estimated $80.57 million in 1986 to almost $500 million in 2010.

Exhibit CWK-1, page 1, shows the pattern of Limerick's costs and benefits over the first 20 years of the plant's service life as forecast in one of the four scenarios used in PECO's life cycle studies. Page 2 of Exhibit CWK-1 is the summary page of PECO's study from which the page 1 data were drawn. The exhibit demonstrates that Limerick's costs exceed its benefits by a factor of about 3.7 in the first year of operation. In the fourth year, 1989, when PECO proposes to impose the greatest cost burden on ratepayers, the benefits are still hardly half the costs (the study assumes no phase-in). It is not until the ninth year, 1994, that the benefits exceed the level of costs. From then on, the cost-benefit ratio improves

dramatically. Benefits are 1.5 times the level of costs in 1995, twice the level in 2002, and three times costs in 2007.

This mismatch between the timing of costs and benefits creates a severe discrimination against PECO's customers during the years 1986 through 1993 in favor of customers during the late 1990's and the 21st Century. This intergenerational discrimination cannot be ignored. It is simply not fair to overcharge customers in 1986 on the promise that they will be undercharged in 1995. They are not the same customers in 1986 and in 1995. Their income, family conditions, life styles and consumption patterns are altogether different. In light of the mobility of the Philadelphia area's population, they are likely not even to be the same people. Cruelest of all is the discrimination against the elderly who are obliged to pay the costs of Limerick, but who are unlikely ever to enjoy its benefits.

Q. The cost curve shown on your Exhibit CWK-1 is merely the result of applying traditional rate-base treatment to Limerick. Why is Limerick any more discriminatory than previous plants that have been included in rate base?

A. To my knowledge, no previous plants have ever displayed such severely negative cost-benefit ratios during their initial years of operation. Nor have any previous plants accounted for such a large increment in the investment, hence the revenue requirement, of PECO. If Limerick did not require a 28 to 40 percent rate increase on its initiation into service, the issue of intergenerational discrimination would probably not be raised because such discrimination would be relatively less.

Q. Why are rate increases of the magnitude proposed by PECO unnecessary?

A. The rate increases proposed by PECO result from the application of conventional rate base treatment to the Limerick plant. This treatment places the entire investment in the Company's rate base at the date of service initiation. The Company is then permitted to collect straight-line depreciation, plus a return on the net investment which, in the initial year, is virtually equivalent to the gross investment. This extraordinarily front-loaded cost recognition is then exaggerated further by the effect of income taxes, which doubles the cost of the return to equity on net undepreciated investment. This tax effect is included in the front-end revenue requirement even though the utility never pays those taxes in the front-end of the plant's service life.

Exhibit CWK-2 is a diagram of the life cycle costs of the Limerick 1 initial investment of $3,176 million. It demonstrates that these costs -- depreciation, return and income taxes -- begin quite high and decline throughout the life of the plant.

There is no valid economic reason why the capital costs of the Limerick plant should be recovered in this manner. They can just as well be distributed more evenly over the life of the plant in a pattern more consistent with incurrence of the benefits from the plant. The fact is that the front loading of capital costs created by "conventional" rate base treatment is unique to the utility industry. In any other industry, it is recognized that the resources necessary to pay for a capital investment are not loaded into the initial years of that investment, but are distributed over its entire service life. Accordingly, the capital cost payments are likewise distributed over the life of the investment.

Consider housing, for example. If the utility rate base treatment were applied to housing, very few houses would be sold. Under that treatment, the first year's payment would reflect a full return on the total investment outstanding plus a straight-line depreciation charge. For a $100,000 home mortgage purchased on a 30-year basis at 12 percent interest, the first year's monthly payments would be calculated as follows:

Investment	$100,000
1/2 year depreciation accrual	1,667
Net investment	98,333
Return @ 12%	11,800
Depreciation	3,333
Annual Payment	15,133
Monthly Payment	$ 1,261

No houses are ever sold in this manner. Rather, the capital costs are established as a level payment over the life of the mortgage. Each year, the amount of interest payment declines and capital recovery increases, such that by the end of the term the lender has received back the full amount of his loan plus interest on the outstanding balance throughout the life of the loans. In the example above, the monthly payment would be $1,029 throughout the life of the mortgage. In the initial year that payment would consist of 96 percent interest and 4 percent capital recovery. In the final year of the mortgage the proportions would be reversed.

The banks and savings & loan associations that finance home mortgages do not object to this procedure because it assures them full capital recovery and a full return on their outstanding investment. Similar arrangements that spread the cost of the Limerick plant more evenly over its service life but assure a full return should be acceptable to PECO as well.

Q. What do you believe is the reason that PECO has not proposed a more levelized capital cost recovery program?

A. I cannot, of course, enter the minds of PECO's management, but I suspect that PECO is concerned that there is no regulatory precedent for a departure from conventional rate base treatment. That treatment has been used throughout the history of utility regulation and has achieved both legal and accounting acceptability. I suspect that PECO fears that a departure from this treatment increases the risk that it may never recover its full capital and return, particularly since any such departure would necessarily involve the deferral of return to later years.

Q. If this is PECO's assessment, do you agree with it?

A. No, I do not. I believe that PECO has overestimated the risks associated with alternative payment procedures that would more evenly and more equitably distribute the costs of Limerick over its service life. There is no question that such alternative procedures would furnish PECO a better opportunity to recover the full costs of its investment in Limerick than its continued insistance on conventional rate base treatment.

Q. Can you suggest any alternative procedures that would more evenly and more equitably distribute the cost of Limerick over its service life?

A. Yes. I can suggest three specific procedures:

- Value based pricing
- Trended rate base
- Levelized payment

Value-Based Pricing

Q. What do you mean by value based pricing?

A. Value-based pricing compensates the utility for the value of the power produced by the plant, in this case Limerick Unit 1. The value of Limerick's power is the savings that the Company, and by extension its customers, experience from the presence of that plant. Thus, value-based pricing compensates the Company in direct proportion to the benefits of the unit. Since PECO's life cycle studies indicate that the benefits from Limerick substantially exceed its costs on a present value basis, it should be feasible to compensate PECO on the basis of Limerick's benefits and still recover fully the costs of the unit inclusive of a return, income taxes and the time value of any deferred revenue.

Q. Can you illustrate this procedure?

A. Yes. Exhibit CWK-1, page 2, is a copy of the summary page of one of PECO's life cycle studies. Column 8 on that page shows the total benefits generated by the Limerick 1 plant each year throughout its 39-year life. Under value-based pricing, this total benefit column would represent the stream of payments for Limerick that would be included in ratepayers' charges. PECO's annual revenue requirements, however, would continue to be calculated according to columns 1 through 4. The difference between column 4 and column 8 would represent the annual additions to and sutraction from a deferred income account similar to the Allowance for Funds Used During Construction (AFUDC). Exhibit CWK-3 is a copy of CWK-1, page 2, with an additional column 10 that shows the cumulative amounts of the deferred compensation each year. This account is compounded each year at

PECO's 9.7 percent after-tax cost of money factor. Note that the deferred compensation account increases through year 15 and then contracts as the total benefits exceed the total costs. Finally, in year 23, the deferred compensation account is completely amortized. In year 24, Limerick would revert to conventional rate base treatment and would be so treated throughout the remainder of its service life.

Each year the Company would record on its books total costs equivalent to column 4.[1/] Each year it would record revenues for Limerick equivalent to that number but separated into two components. Cash income, which would be reflected in rates, would equal column 8, and non-cash "other income" would equal the net of column 9 and 9.7 percent (or whatever the AFUDC rate is) of the previous year's balance. That non-cash income would be capitalized into an asset account representing Limerick 1 credits. Each year that asset account would compound at PECO's AFUDC rate which, for purposes of this illustration, is shown as 9.7 percent. After year 8, when the benefits begin to exceed costs, the Company would continue to receive cash revenue in accordance with its benefits. As the benefits mount, the spread over cost will increase and the deferred compensation account will be amortized.

Q. What are the advantages of value-based pricing?

A. The principal advantage of value-based pricing is that it eliminates altogether the intergenerational discrimination associated with

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[1/] Column 4 would be reduced for this purpose if return is deferred but not taxes, so that taxes are charged to ratepayers each year as incurred. This treatment would reduce the deferred revenue account and shorten the period of its amortization.

conventional rate base treatment. Each year, ratepayers are charged for Limerick according to the benefits they receive from the plant. They never pay more than they would pay had Limerick never been built.

A subsidiary benefit is that value-based pricing renders moot the issues of the prudency of Limerick investment. PECO is paid for Limerick only to the extent that it proves to be a prudent investment. Ratepayers are never asked to pick up any of the net costs of Limerick, i.e, costs that are discretely caused by the plant. Quite the contrary, their costs are those of not having the plant.

Q. What are the disadvantages of value-based pricing?

A. While the advantages of value-based pricing are theoretical, the disadvantages are practical. In theory, the value-based pricing charges to ratepayers should be based on an annual calculation of Limerick benefits. Not only are such calculations imprecise and subject to controversy, but they are totally unpredictable. This unpredictability would substantially increase PECO's risk, and that increased risk itself has a cost. Indeed, it is unlikely that PECO would be permitted to carry the deferred compensation account on its books as an asset if it had to rely on annual benefit calculations as to the basis of repayment.

A possible solution might be to fix the stream of cash payments from ratepayers at the initiation of the plant in service based on the best assessment of benefits at that time. This stream would represent the ratepayer contribution through the point of cross-over when benefits exceed costs (year 8 in the illustration in CWK-1). At that point Limerick could be taken into rate base, and the deferred revenue account would be amortized

on a fixed schedule over, say, ten years. This procedure would minimize PECO's exposure to the uncertainty of repayment, particularly in the later years when the level of Limerick benefits is highly unpredictable.

Another arguable disadvantage of value-based pricing relates to the immediate future, 1986, 1987, 1988. Under value-based pricing, PECO would receive no immediate increase in revenue whatsoever. Its only cash compensation for Limerick would be $231 million in saved fuel costs and avoided capacity charges. This very limited payment may not be sufficient to maintain the Company's financial health and, more specifically, its ability to finish Limerick Unit 2. If so, it may be necessary to override value-based pricing and grant PECO some further increase sufficient to maintain its cash flow requirements.

Trended Rate Base

Q. What is a trended rate base?

A. One of the intergenerational inequities of conventional rate base treatment is that it fails to recognize the effect of inflation on the value of the rate base. It treats a dollar of plant in year 1 as having the same value as in year 10, year 20, or year 30. Yet, the year 1 dollar is much more valuable than the year 10 dollar, which in turn is more valuable than the year 20 or year 30 dollar, especially with inflation.

This failure to recognize the changing value of the dollar exaggerates the front-end loading of conventional rate base treatment. In year 1, when net investment is at its highest, investors pay the greatest return dollars at any time during the life of the plant. In turn, those dollars have the greatest value of any dollars paid during the life of the

plant. Even depreciation charges, which are presumably level over the plant's life, are in fact much greater -- in buying power terms -- in the first year than at anytime in the plant's service life.

To illustrate, the return requirement for Limerick's initial $3.2 billion is $406.3 million in 1986 and only $236 million in 1996, but at 6 percent inflation, the value of those 1996 dollars in 1986 terms is only $132 million. Similarly, the depreciation on the initial $3.2 billion in Limerick is $81.4 million throughout its service life. Again assuming 6 percent inflation, the real value of this depreciation charge by 1996 is only $45.5 million.

A trended rate base attempts to adjust the value of the rate base for the decline in the value of the dollar. It does this by increasing the rate base each year by the amount of inflation to create, in effect, a constant dollar rate base. The annual return charged to ratepayers is only the true interest, that is, the portion of return that represents the differential between the overall rate of return and the rate of inflation. In nominal, i.e., current dollars, this return begins fairly low and grows as the rate base grows -- a reversal from conventional treatment. Similarly, depreciation appears to grow in nominal dollars, although in constant dollars it remains perfectly level throughout the life of the plant.

Q. Can you illustrate the trended rate base procedure?

A. Yes. Exhibit CWK-4 compares the year-to-year revenue requirement for the initial $3,176 million in Limerick investment as computed by PECO under conventional rate base treatment and, alternatively, under the trended rate base. Under trended rate base, there are two rates of return (lines 9

and 10 of pages 2 through 7). One is the cash return rate and the other is the deferred return rate, with the latter being the rate of inflation. For this illustration, I have used the rates of inflation forecast by PECO in its life cycle studies. The cash return is incorporated into PECO's revenue requirements each year. The deferred return is capitalized and added to the rate base for the subsequent year (line 2).

Each year, this rate base increases and so the current dollar value of the revenue requirement increases, as well, as shown on page 1a of Exhibit CWK-4.[1/] However, as shown on page 1b of that exhibit, the constant dollar value of the revenue requirement actually declines. Thus, the burden on the purchasing power of ratepayers diminishes as the benefits of the plant increases.

Q. Does trended rate base pricing require a commitment to a fixed rate of cash and deferred return throughout the life of the plant?

A. No, it does not. In fact, the mix of cash and deferred return should be adjusted whenever the Company's overall rate of return is adjusted, since the sum of the two should equal that overall return. The only additional determination that is required to implement trended rate base is to separate the overall return into the two components of pure interest and inflation premium. The latter should equal the current or near term predicted rate of inflation.

1/ This continuously increasing nominal dollar revenue requirement is largely due to the assumption of a 51 percent income tax. If the tax rate were reduced to 35 percent, as recently proposed in Congress, the revenue requirements would decline even in nominal dollars.

Q. How would operating and maintenance costs be treated under trended rate base?

A. Unlike value-based pricing, which covers all costs related to the nuclear plant, trended rate base applies only to capital costs. Operating and maintenance costs would be incorporated into the annual revenue requirement independently of the trended rate base treatment.

Q. What would be the initial year rate increase under trended rate base?

A. Page 2 of Exhibit CWK-4 shows that the initial year capital costs of Limerick under trended rate base would be $419.38 million. Using the figures from PECO's life-cycle study (CWK-1, page 2), operating and maintenance costs would amount to $110.25 million, while the offsetting savings in fuel and capacity charges would be $231.39 million. The net increase to ratepayers would be $298.24 million, or 12.5 percent, compared with PECO's proposed $671 million, or 28.2 percent. 1/

Q. What are the advantages and disadvantages of trended rate base?

A. Trended rate base does not altogether eliminate the front-loading of capital costs into the initial years of the plant's service life because, unlike value-based pricing, it does not coordinate the incurrence of costs with the occurrence of benefits. On the other hand, trended rate base avoids the requirement to forecast prospective benefits from the nuclear plant. Rather, it is based on the plant's own costs. It is much more

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1/ Exhibit CWK-4 does not reflect the effect of deferred taxes which would reduce the revenue requirement further during the early portion of the plant's service life.

consistent with conventional rate base treatment and can easily be incorporated into existing accounting procedures.

The principal difficulty with trended rate base is that it appears to create an ever increasing revenue requirement throughout the plant's life. As I have pointed out, the real cost to ratepayers actually declines, but the apparent cost increases could still make the trended rate base increasingly unpopular as the plant ages.

Levelized Payment

Q. Would you please describe the levelized payment concept?

A. This concept is directly analogous to the level payment plans that apply to home mortgages. It simply creates a level revenue requirement amount throughout the life of the plant using the Company's after-tax rate of return as the equivalent of the home mortgage interest.

Q. Could you please illustrate the level payment concept?

A. Yes. The initial investment in Limerick 1 and associated common plant is $3,176,476,000, and the plant is forecast to operate for 39 years. The requested rate of return is 12.79 percent. These factors can be substituted into the conventional mortgage formula:

$$\text{payment} = A \frac{i(1+i)^n}{(1+i)^n - 1}$$

where i = rate of return
n = number of payments
A = initial investment

The resultant levelized payment is $410.02 million. Income taxes on this charge would be about $53 million. Again using data from PECO's life cycle studies, the payment, when combined with operating and maintenance expense

and netted against fuel and capacity charge savings, would yield a net one-time increase of $340 million, or 14.8 percent. Subsequent rate adjustments would reflect only changes in O&M costs and in fuel and capacity charge savings.

Q. How would the levelized payment plan be incorporated into the Company's books?

A. The levelized payment would be used only to calculate the pre-tax capital cost contribution from ratepayers. The Company would compute its annual depreciation and return in conventional fashion. The differential between the conventional capital costs and the level payment would be declared "other income" and capitalized into a deferred revenue asset account. That deferred account would compound at the after-tax return rate. The deferred revenue account would build in the initial years of the plant's service life and then decline once the level payments exceeded the sum of depreciation and return on rate base.[1/]

Taxes would be treated on an as-incurred basis and would be added to the level payment as part of ratepayer revenue requirement. This treatment should create a levelized tax payment to match the levelized capital cost contribution.

Q. What are the advantages and disadvantages of the levelized payment plan?

1/ An alternative is to employ "sinking fund depreciation," which sets the annual depreciation charge equal to the capital recovery portion of the level payment. The objection to this procedure is that it front-loads income taxes into the initial years when return is quite high and depreciation quite low. Utilities have also objected to the back-loading of capital recovery which they see as increasing their risk.

A. The levelized payment plan is by far the simplest and most straightforward of the three plans I have suggested. It has precedent and acceptance in the business and financial -- if not the regulatory -- communities. On the other hand, it involves the least deferral of revenue recovery out of the initial low-benefit years and therefore does the least to redress the discrimination of conventional rate base treatment among generations of ratepayers.

Q. Would you please summarize your testimony thus far?

A. I have described three alternative procedures whereby the damaging effects of the rate shock increase proposed by PECO can be eliminated or substantially reduced without the loss of a single dollar of capital recovery or return to PECO. All three of these procedures have the common characteristic of establishing an asset account that represents the revenue deferred from the early years of Limerick's operation, during which it has a negative cost-benefit ratio, into the later years when that cost-benefit ratio becomes positive. Not only do these procedures reduce the immediate rate increase imposed on ratepayers, but they shift the timing of revenue recovery into greater symmetry with benefit incurrence.

Q. What do you recommend with respect to these procedures?

A. In order for these plans to be acceptable, PECO needs assurance that the deferral of revenue proposed in these plans will not translate into a loss of revenue. It is therefore necessary to incorporate whatever procedures are adopted into the accounting calculation used in all future rate proceedings. Specifically, the deferred revenues must be recorded in asset accounts that are clearly identified as funds owed by ratepayers to

the Company. They should be perceived as the reverse of the deferred tax accounts, which are funds owed by the Company to ratepayers. In this manner future Commissions will not be tempted to abrogate the intergenerational agreement to transfer revenue recovery from the early years of the Limerick plant to later years.

PECO's Phase-In Plan

Q. Are there any other issues that you would like to discuss with respect to PECO's proposed rate increase?

A. Yes. I would like to address PECO's proposal with respect to the recovery of the revenue deferred during the first three years under its phase-in plan. There are aspects of this proposal that I believe to be severely discriminatory, or at least potentially so.

Q. What are these severely discriminatory aspects of PECO's phase-in program?

A. I refer to PECO's plan to accumulate the revenue deferred during the first three years in accounts that correspond with the respective customer classes and rate elements within each tariff schedule. PECO proposes that these "pots" of deferred revenue be recaptured from the same classes and from the same rate elements during the subsequent four years. For example, demand charges for the HT customers deferred during 1986, 1987 and 1988 will be recaptured solely through increases in demand charges for HT customers beginning in 1989.

Q. What is your objection to this procedure?

A. This procedure reflects to some extent the same mentality that operates with respect to the overall revenue requirement, namely, the

assumption that customers in 1986 are interchangeable with customers in 1989 and thereafter. There is no assurance whatever that the customer mix of, say, the HT class in 1989 through 1990 will be the same as in 1986. Even if most of the customers are the same, certainly not all will be. Yet the remaining customers will be affected by the movement of new customers in and old customers out of the rate schedule during the phase-in period. If a customer class grows during this phase-in period, then the burden on the present customers that are still within the class in 1989-1991 will be reduced. Conversely, if there is a contraction in the aggregate size of the customer class, then the customers who remain within that class experience an increase in their revenue requirements.

I do not believe it is fair to base the charges to one customer on the presence or absence of other customers within the same class. There is no causal justification for charging HT class department stores higher rates in 1989 because the Philadelphia area steel industry, which also happens to be in Class HT, has curtailed production between 1986 and 1989. Conversely, there is no reason why the retail stores in the PD category should receive a proportionate rate reduction in 1990 simply because some additional office buildings have been constructed in downtown Philadelphia. Yet such would be the result of PECO's proposal to maintain class "pots" of deferred revenue.

The proposal is even worse than that. If the load profile of the class changes, the revenue recovery rates are influenced as well. The HT class, for example, contains a number of manufacturing operations that work several shifts a day, yielding fairly high load factors. If one or two major industrial customers were to cut back from, say, a three-shift

to a two-shift operation, the effect would be to increase the energy charges in 1989 with no reduction in demand charges. Such a change would burden high load factor HT customers through no fault of their own. Conversely, if major industrial customers institute peak shaving through internal generation, then the demand charge in 1989 will increase relative to the energy charges, and other high-load-factor customers will be damaged, again through no fault of their own.

Q. How should the deferred revenue be recovered?

A. The only equitable procedure for treating deferred revenue is to incorporate it into the aggregate revenue requirement for recovery from all customer classes according to rate schedules whose constituent demand and energy charges are based on a cost of service study. In this manner, the distortive effects of different customer class growth rates and changes in load profiles will be eliminated and the burden of deferred revenue recovery distributed among customers according to their cost incurrence.

II. LIMERICK COST ALLOCATION

Q. What is the principal issue of cost allocation relative to thie Limerick plant?

A. In my opinion the principal issue of cost allocation is the distribution of Limerick 1 capital costs between energy and demand.

Q. How has PECO assigned Limerick capital costs between energy and demand?

A. PECO has treated Limerick 1 capital costs as solely related to demand and has allocated these costs among classes according to the four

coincident peak (4-CP) allocation key. It has also flowed these costs into the demand components of the constituent rate schedules in the Company's tariff.

Q. What is the rationale for allocating Limerick costs to the demand function?

A. The conventional rationale for allocating production plant capital costs to demand is that the requirement to construct generating plants is driven by the maximum demand on the system during the year. As that maximum demand grows, it is necessary to build additional plants, the latest of which is the Limerick 1 unit.

Q. Is this an appropriate rationale when applied to Limerick?

A. To a limited extent, it is. The Company's figures suggest that, absent the Limerick plant, the margin of capacity over peak load would become unacceptably low. Thus, the capacity furnished by the Limerick plant has indeed been constructed to meet peak load requirements.

Peak load growth did not, however, dictate the requirement to build a nuclear plant. If the only consideration was to meet the growth in peak demand, PECO could have constructed combustion turbines to act as peaker units to serve that maximum load. Such combustion turbines would have incurred a fraction of the capital costs required for Limerick. Specifically, the Potomac Electric Power Company recently conducted a study which indicated that peaker generating units can be built for approximately $396 per kw. In contrast, Limerick cost $3,621 per kw. The difference between the $396 peaker cost and the $3,621 cost of Limerick cannot be ascribed to peak demand. The reason Limerick was built as a nuclear plant

relates to energy, specifically, the long term objective of reducing the per kwh cost of baseload power. If Limerick performs up to its expected capacity utilization, it will indeed be successful in this function, and ratepayers will enjoy a benefit of $207.7 million in 1986 rising to $1 billion by 1995 and $3 billion by the year 2010. These savings will accrue to users of energy throughout PECO's entire load curve, including the off-peak hours. Since the savings relate to energy, the costs associated with nuclear construction should be assigned to energy as well.

Q. How would you recommend allocating the costs of the Limerick unit?

A. I propose that the cost of a peaker unit, which I have taken as $396 per kw, be allocated to demand, and the remaining cost of Limerick be assigned to energy. In this manner, there will be a symmetry between the energy savings of Limerick and the allocation of its capital costs.

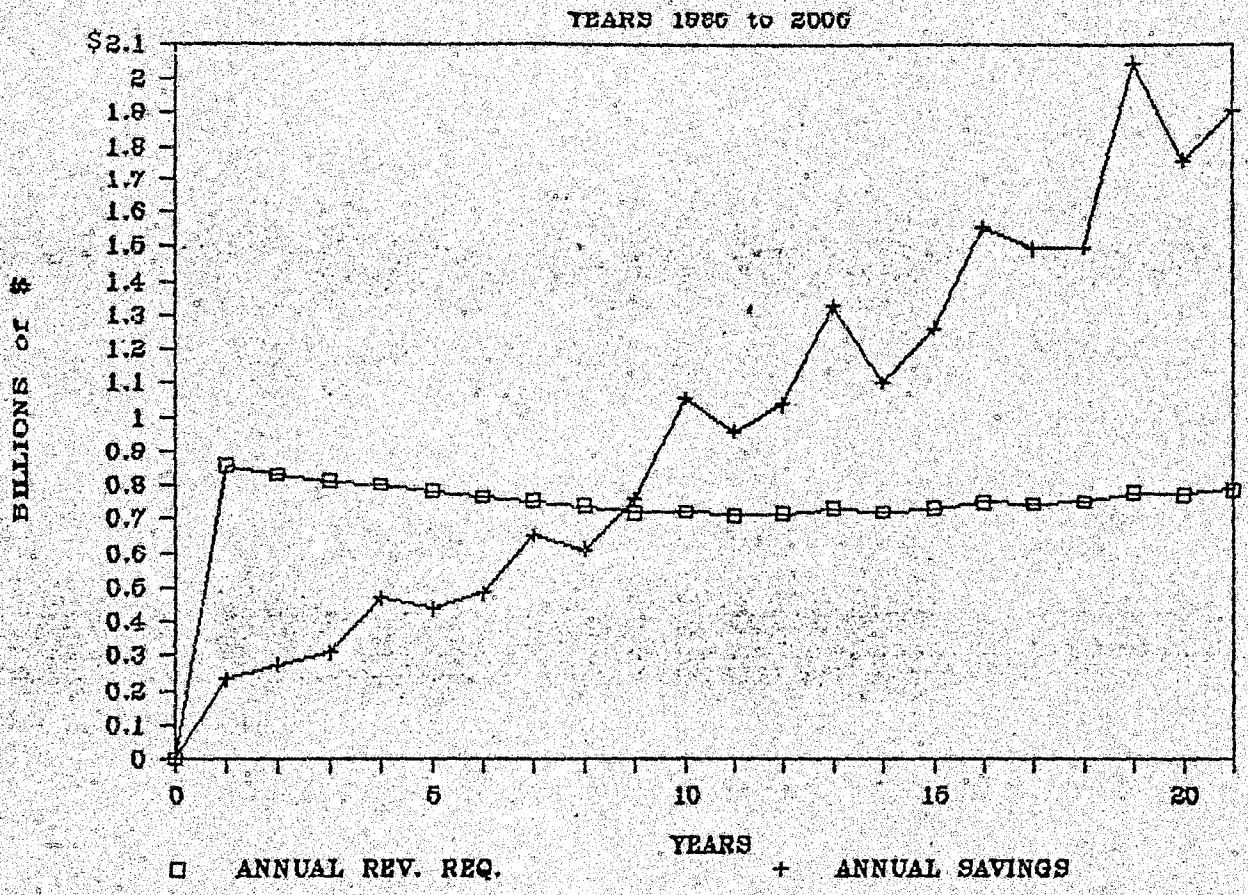
Q. Have you performed a cost allocation study on this basis?

A. I have recommended this methodology to Mr. Figley and he has incorporated it into his recast of PECO's cost of service and rate design studies.

Q. Does this conclude your testimony?

A. Yes, it does.

LIMERICK UNIT No.1 COST v. BENEFIT



Source: Attachment IR-OCA-2-25b, Item 1, Page 1 of 3.

LIMERICK UNIT NO. 1 & 50% COMMON
FUEL SAVINGS/W LOAD SHED AND ACID RAIN
ANNUAL REVENUE REQUIREMENTS
MILLIONS$

9/23/85

100% increase in capacity charges

EL-OCA-2
ITEM 1, 3 pages

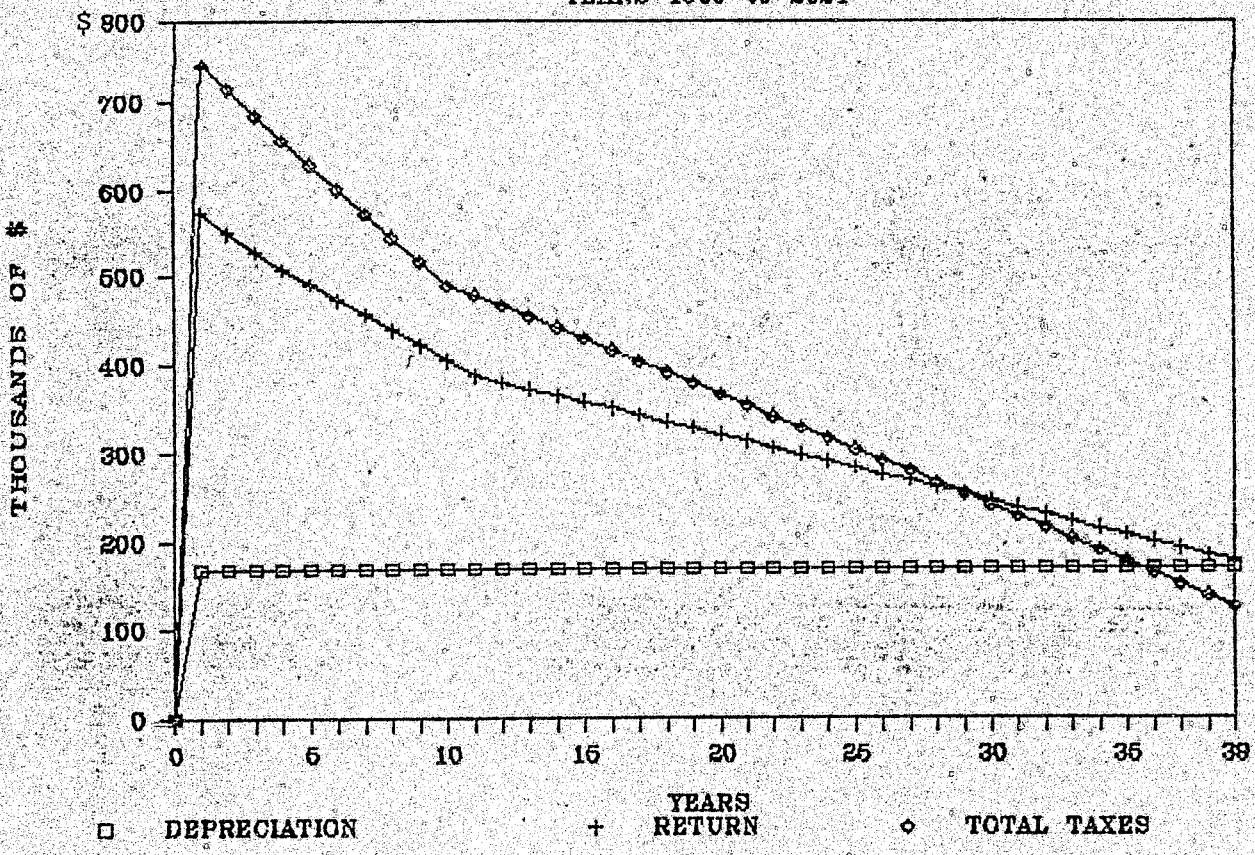
YEAR		ORIG COST $ADDITIONS CARRYING CHARGES(a) (1)	STATION O&M (2)	OTHER O&M(b) (3)	TOTAL COSTS (4)=(1)+(2) +(3)	O & M AND CAPITAL DIFFERENTIAL FOR SO2 AND NOX (5)	FUEL SAVINGS(c) (6)	50% redin 2 party pur 2x rate CAPACITY CHARGES AVOIDED (7)	TOTAL BENEFITS (8)=(5)+(6) +(7)	BREAKEVEN NPV AT 2008 16.83581720 BENEFITS LESS COSTS (9)=(8)-(4)
1	1986	$747.27	$79.01	$31.24	$857.52	$0.00	$150.82	$80.57	$231.39	($626.13)
2	1987	$713.90	$85.33	$31.62	$830.85	$0.00	$186.04	$88.78	$274.82	($556.03)
3	1988	$685.60	$93.01	$32.98	$811.59	$0.00	$209.45	$97.23	$306.68	($504.91)
4	1989	$660.09	$101.39	$39.96	$801.44	$0.00	$322.35	$144.03	$466.39	($335.05)
5	1990	$635.23	$110.51	$33.90	$779.64	$0.00	$282.46	$152.68	$435.14	($344.50)
6	1991	$610.30	$117.14	$37.10	$764.54	$0.00	$320.80	$161.84	$482.64	($281.90)
7	1992	$585.46	$124.17	$41.19	$750.82	$0.00	$480.03	$171.54	$651.57	($99.25)
8	1993	$560.69	$131.62	$43.70	$736.01	$2.77	$423.14	$181.84	$607.75	($128.26)
9	1994	$536.03	$139.52	$40.96	$716.51	$2.83	$560.85	$192.75	$756.43	$39.92
10	1995	$511.44	$147.89	$57.53	$716.86	$2.91	$843.13	$204.31	$1,050.35	$333.49
11	1996	$504.40	$156.76	$48.41	$709.57	$3.07	$734.74	$216.57	$954.38	$244.81
12	1997	$495.18	$166.17	$51.62	$712.97	$3.04	$799.49	$229.57	$1,032.10	$319.13
13	1998	$486.13	$176.14	$65.35	$727.63	$3.12	$1,072.74	$243.35	$1,319.21	$591.58
14	1999	$477.26	$186.70	$54.99	$718.95	$3.35	$834.45	$257.95	$1,095.76	$376.81
15	2000	$468.59	$197.91	$61.72	$728.22	$3.07	$979.39	$273.43	$1,255.89	$527.67
16	2001	$460.10	$209.78	$75.58	$745.46	$3.18	$1,256.13	$289.85	$1,549.16	$803.70
17	2002	$451.84	$222.37	$65.12	$739.33	$3.44	$1,175.93	$307.24	$1,486.61	$747.28
18	2003	$443.83	$235.71	$59.60	$749.14	$3.76	$1,158.32	$325.68	$1,487.76	$738.62
19	2004	$436.03	$249.85	$88.42	$774.30	$4.31	$1,684.26	$345.22	$2,033.79	$1,259.49
20	2005	$428.51	$264.84	$76.04	$769.39	$4.64	$1,377.00	$365.94	$1,747.58	$978.19
21	2006	$421.25	$280.73	$81.50	$783.48	$4.88	$1,501.83	$387.90	$1,894.61	$1,111.13
22	2007	$414.35	$297.58	$101.84	$813.77	$5.16	$2,085.02	$411.18	$2,501.36	$1,687.59
23	2008	$407.75	$315.43	$88.98	$812.16	$5.61	$1,826.78	$435.84	$2,268.23	$1,456.07
24	2009	$401.54	$334.35	$94.61	$830.51	$5.94	$1,823.03	$461.98	$2,290.95	$1,460.44
25	2010	$395.74	$354.42	$120.16	$870.32	$6.27	$2,684.52	$489.71	$3,180.50	$2,310.18
26	2011	$390.37	$375.69	$103.97	$870.03	$6.64	$2,226.64	$519.10	$2,752.38	$1,882.35
27	2012	$385.52	$398.23	$111.33	$895.08	$6.88	$2,386.35	$550.25	$2,943.48	$2,048.40
28	2013	$381.21	$422.12	$140.89	$944.22	$7.12	$3,393.46	$583.27	$3,983.85	$3,039.63
29	2014	$377.54	$447.45	$121.90	$946.89	$7.56	$2,946.52	$618.27	$3,572.35	$2,625.46
30	2015	$374.64	$474.30	$130.85	$979.79	$7.84	$3,011.42	$655.37	$3,674.63	$2,694.84
31	2016	$367.56	$502.75	$166.29	$1,036.60	$8.12	$4,511.25	$694.70	$5,214.07	$4,177.47
32	2017	$363.16	$532.92	$143.46	$1,039.54	$8.63	$3,726.32	$736.37	$4,471.32	$3,431.78
33	2018	$361.90	$564.89	$154.33	$1,081.12	$8.94	$3,797.64	$780.55	$4,587.13	$3,506.01
34	2019	$364.73	$598.79	$195.17	$1,158.69	$9.28	$5,489.06	$827.39	$5,325.73	$5,167.04
35	2020	$373.05	$634.71	$170.44	$1,178.20	$9.92	$4,658.72	$877.04	$5,545.68	$4,367.48
36	2021	$390.15	$672.80	$182.35	$1,245.30	$10.25	$4,949.91	$929.67	$5,889.83	$4,644.53
37	2022	$421.66	$713.17	$231.63	$1,366.46	$10.63	$7,318.66	$985.45	$8,314.74	$6,948.28
38	2023	$481.89	$755.96	$201.11	$1,438.96	$11.35	$6,275.86	$1,044.58	$7,331.79	$5,892.83
39	2024	$627.67	$801.31	$216.47	$1,645.45	$11.80	$6,789.08	$1,107.24	$7,908.12	$6,262.67
TOTALS		$18,599.56	$12,673.43	$3,804.32	$35,077.31	$196.32	$86,253.60	$17,426.23	$103,876.15	$68,798.84
pv@ 9.70%-1985$		$5,707.55	$1,725.15	$556.67	$7,989.37	$21.54	$8,679.30	$2,312.34	$11,013.18	$3,023.81
									GRT= 4.50%	$3,166.29

(a) INCLUDES SUBSEQUENT CAPITAL ADDITIONS
(b) DECOMMISSIONING, SPENT FUEL, INSURANCE, AND IN-REACTOR INTEREST
(c) SOBIS SAVINGS AND SAVINGS BY NOT INCURRING LOAD SHEDDING COSTS

Exhibit CWK-2

LIMERICK No.1 INITIAL CAPITAL COSTS

YEARS 1986 to 2024



Source: Attachment IR-OCA-2-25b, Item 7, Pages 1 to 6.

LIMERICK U[illegible] NO. 1 & 50% COMMON — 9/23/85 — ITEM 1, 3 page

FUEL SAVINGS/W LOAD SHED AND ACID RAIN

ANNUAL REVENUE REQUIREMENTS

100% increase in capacity charges

$MILLIONS

50% redin 2 party pur 2x rate

BREAKEVEN NPV AT 2008 16.83581720

YEAR		ORIG COST $ADDITIONS CARRYING CHARGES(a) (1)	STATION O&M (2)	OTHER O&M(b) (3)	O & M AND CAPITAL TOTAL COSTS (4)=(1)+(2)+(3)	DIFFERENTIAL FOR SO2 AND NOX (5)	FUEL SAVINGS(c) (6)	CAPACITY CHARGES AVOIDED (7)	TOTAL BENEFITS (8)=(5)+(6)+(7)	BENEFITS LESS COSTS (9)=(8)-(4)	DEFERRED REVENUE (10)
1	1986	$747.27	$79.01	$31.24	$857.52	$0.00	$150.82	$80.57	$231.39	($626.13)	626.13
2	1987	$713.90	$85.33	$31.62	$830.85	$0.00	$186.04	$88.78	$274.82	($556.03)	1242.89
3	1988	$685.60	$93.01	$32.98	$811.59	$0.00	$209.45	$97.23	$306.68	($504.91)	1868.36
4	1989	$650.09	$101.39	$39.96	$801.44	$0.00	$322.35	$144.03	$466.39	($335.05)	2384.64
5	1990	$635.23	$110.51	$33.90	$779.64	$0.00	$282.46	$152.68	$435.14	($344.50)	2960.45
6	1991	$610.30	$117.14	$37.10	$764.54	$0.00	$320.80	$161.84	$482.64	($281.90)	3529.51
7	1992	$585.46	$124.17	$41.19	$750.82	$0.00	$480.03	$171.54	$651.57	($99.25)	3971.12
8	1993	$560.69	$131.62	$43.70	$736.01	$2.77	$423.14	$181.84	$607.75	($128.26)	4484.58
9	1994	$536.03	$139.52	$40.96	$716.51	$2.83	$560.85	$192.75	$756.43	$39.92	4879.66
10	1995	$511.44	$147.89	$57.53	$716.86	$2.91	$843.13	$204.31	$1,050.35	$333.49	5019.50
11	1996	$504.40	$156.76	$48.41	$709.57	$3.07	$734.74	$216.57	$954.38	$244.81	5261.58
12	1997	$495.18	$166.17	$51.62	$712.97	$3.04	$799.49	$229.57	$1,032.10	$319.13	5452.82
13	1998	$486.13	$176.14	$65.36	$727.63	$3.12	$1,072.74	$243.35	$1,319.21	$591.58	5390.16
14	1999	$477.26	$186.70	$54.99	$718.95	$3.36	$834.45	$257.95	$1,095.76	$376.81	5536.20
15	2000	$468.59	$197.91	$61.72	$728.22	$3.07	$979.39	$273.43	$1,255.89	$527.67	5545.54
16	2001	$460.10	$209.78	$75.58	$745.46	$3.18	$1,256.13	$289.85	$1,549.16	$803.70	5279.76
17	2002	$451.84	$222.37	$65.12	$739.33	$3.44	$1,175.93	$307.24	$1,486.61	$747.28	5044.62
18	2003	$443.83	$235.71	$69.60	$749.14	$3.76	$1,158.32	$325.68	$1,487.76	$738.62	4795.33
19	2004	$436.03	$249.85	$88.42	$774.30	$4.31	$1,684.26	$345.22	$2,033.79	$1,259.49	4000.99
20	2005	$428.51	$264.84	$76.04	$769.39	$4.64	$1,377.00	$365.94	$1,747.58	$978.19	3410.90
21	2006	$421.25	$280.73	$81.50	$783.48	$4.88	$1,501.83	$387.90	$1,894.61	$1,111.13	2630.63
22	2007	$414.35	$297.58	$101.84	$813.77	$5.16	$2,085.02	$411.18	$2,501.36	$1,687.59	1198.21
23	2008	$407.75	$315.43	$88.98	$812.16	$5.61	$1,826.78	$435.84	$2,268.23	$1,456.07	0.00
24	2009	$401.54	$334.35	$94.61	$830.51	$5.94	$1,823.03	$461.98	$2,290.95	$1,460.44	
25	2010	$395.74	$354.42	$120.16	$870.32	$5.27	$2,684.52	$489.71	$3,180.50	$2,310.18	
26	2011	$390.37	$375.69	$103.97	$870.03	$5.64	$2,226.64	$519.10	$2,752.38	$1,882.35	
27	2012	$385.52	$398.23	$111.33	$895.08	$6.88	$2,386.35	$550.25	$2,943.48	$2,048.40	
28	2013	$381.21	$422.12	$140.89	$944.22	$7.12	$3,393.46	$583.27	$3,983.85	$3,039.63	
29	2014	$377.54	$447.45	$121.90	$946.89	$7.56	$2,946.52	$618.27	$3,572.35	$2,625.46	
30	2015	$374.64	$474.30	$130.85	$979.79	$7.84	$3,011.42	$655.37	$3,674.63	$2,694.84	
31	2016	$367.56	$502.75	$166.29	$1,036.60	$8.12	$4,511.25	$694.70	$5,214.07	$4,177.47	
32	2017	$363.16	$532.92	$143.46	$1,039.54	$8.63	$3,726.32	$736.37	$4,471.32	$3,431.78	
33	2018	$361.90	$564.89	$154.33	$1,081.12	$8.94	$3,797.64	$780.55	$4,587.13	$3,506.01	
34	2019	$364.73	$598.79	$195.17	$1,158.69	$9.28	$5,489.06	$827.39	$6,325.73	$5,167.04	
35	2020	$373.05	$634.71	$170.44	$1,178.20	$9.92	$4,658.72	$877.04	$5,545.68	$4,367.48	
36	2021	$390.15	$672.80	$182.35	$1,245.30	$10.25	$4,949.91	$929.67	$5,889.83	$4,644.53	
37	2022	$421.66	$713.17	$231.63	$1,366.46	$10.63	$7,318.66	$985.45	$8,314.74	$6,948.28	
38	2023	$481.89	$755.96	$201.11	$1,438.96	$11.35	$5,275.86	$1,044.58	$7,331.79	$5,892.83	
39	2024	$627.67	$801.31	$216.47	$1,645.45	$11.80	$5,789.08	$1,107.24	$7,908.12	$6,262.67	
TOTALS		$18,599.56	$12,673.43	$3,804.32	$35,077.31	$196.32	$86,253.60	$17,426.23	$103,876.15	$68,798.84	
pv@ 9.70%-1985$		$5,707.55	$1,725.15	$556.67	$7,989.37	$21.54	$8,679.30	$2,312.34	$11,013.18	$3,023.81	
									GRT= 4.50%	$3,166.29	

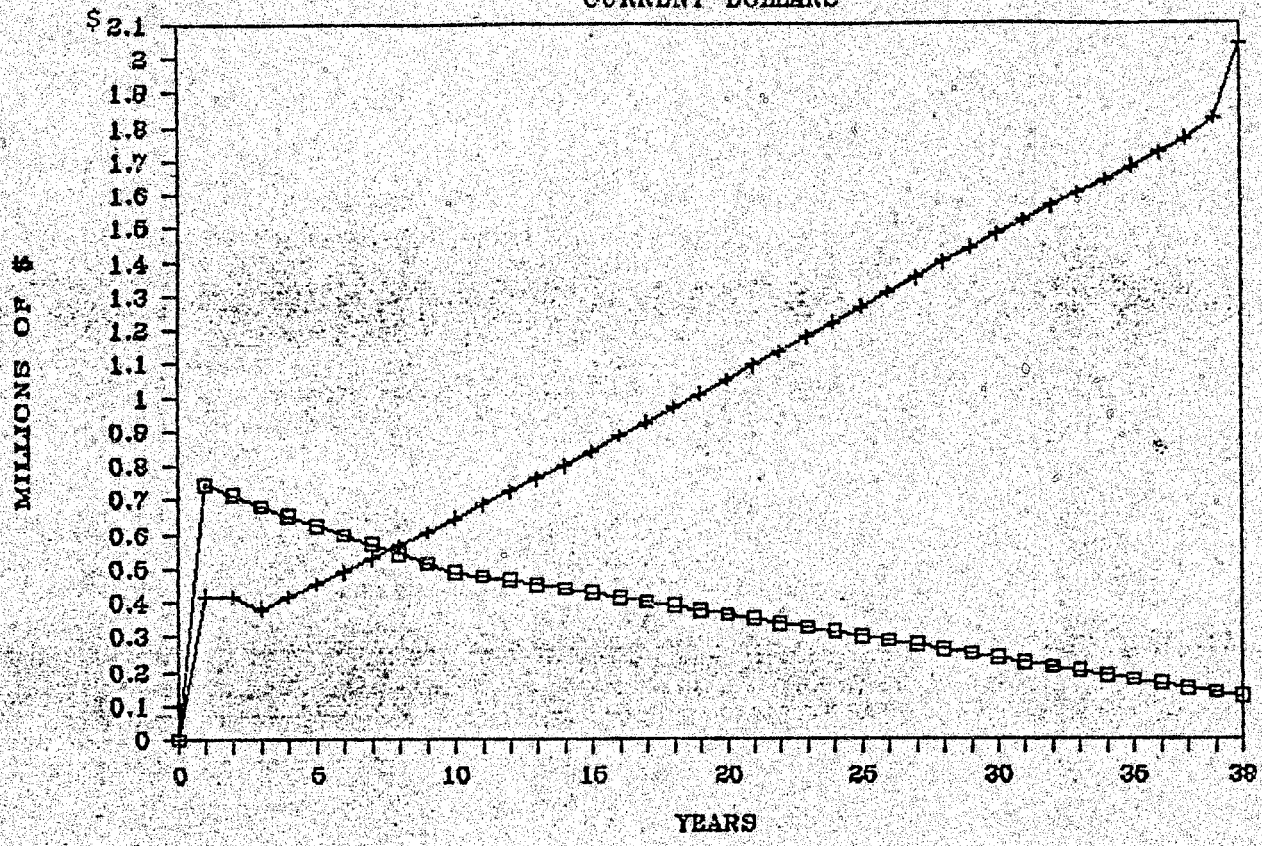
(a) INCLUDES SUBSEQUENT CAPITAL ADDITIONS

(b) DECOMMISSIONING, SPENT FUEL, INSURANCE, AND IN-REACTOR INTEREST

(c) SO2IG SAVINGS AND SAVINGS BY NOT INCURRING LOAD SHEDDING COSTS

LIMERICK No.1 CAPITAL COSTS

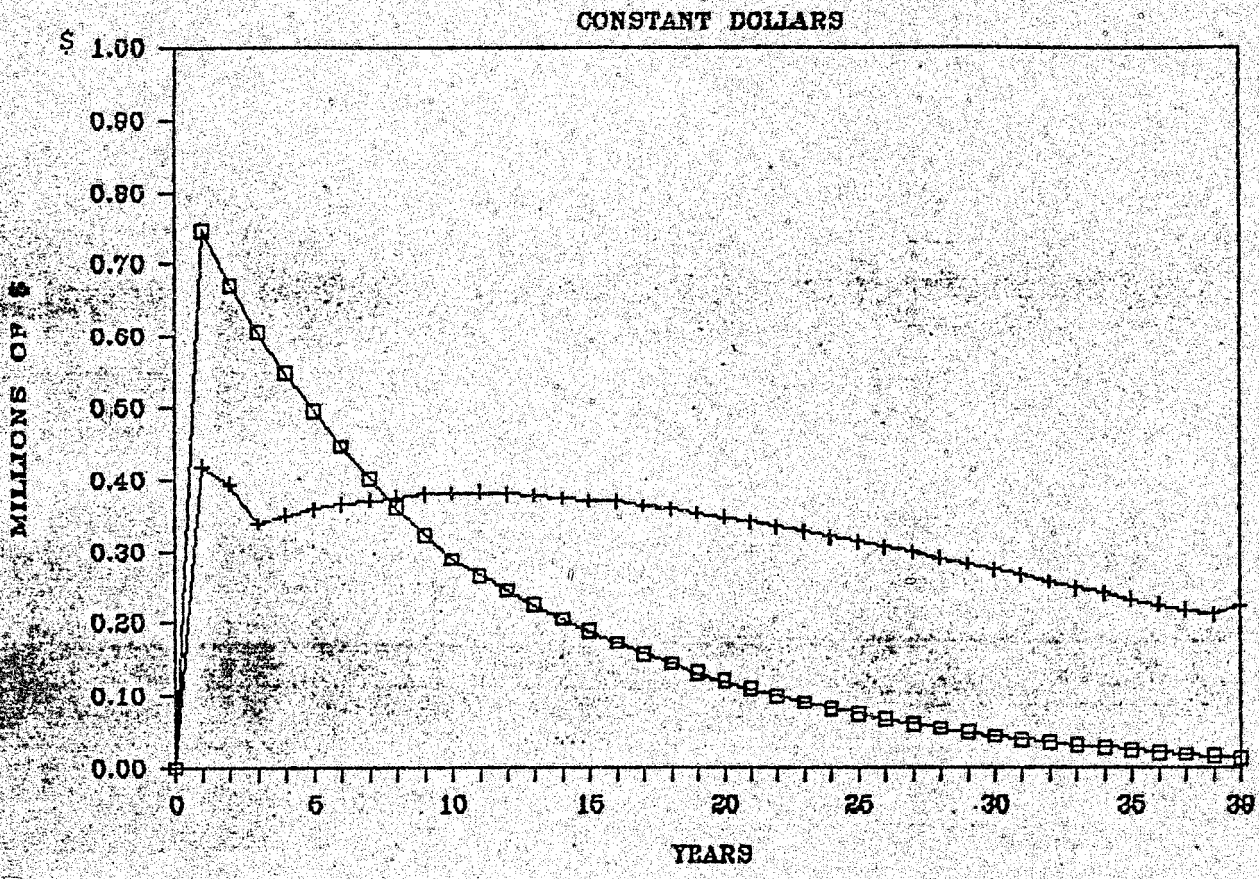
CURRENT DOLLARS



□ - CONVENTIONAL RATE BASE

\+ - TRENDED RATE BASE

LIMERICK No.1 CAPITAL COSTS



PHILADELPHIA ELECTRIC COMPANY

Illustration of Trended Rate Base on Limerick 1 Initial Investment

Line No.	Description	Source	1986	1987	1988	1989	1990	1991	1992
1.	Initial Capital	OCA-2-25b.7 L1	3176476	3176476	3176476	3176476	3176476	3176476	3176476
2.	Accumulated Deferred Rat.	Total L11 prev. yrs.	0	142941	304839	503718	709155	921212	1139933
3.	Total Capital	L1 + L2	3176476	3319417	3481315	3680194	3885631	4097688	4316409
4.	Accumulated Depreciation	Total L7 prev. yrs.	0	81448	166658	256243	351353	452332	559548
5.	Net Investment	L3 - L4	3176476	3237969	3314657	3423951	3534278	3645356	3756861
6.	Remaining Life Years	Given	39	38	37	36	35	34	33
7.	Remaining Life Depreciatn	L5 / L6	81448	85210	89585	95110	100979	107216	113844
8.	Overall Return	PECO request	.1279	.1279	.1279	.1279	.1279	.1279	.1279
9.	Inflation Rate	OCA-2-25b	.045	.05	.06	.06	.06	.06	.06
10.	Cash Return Rate	L8 - L9	.0829	.0779	.0679	.0679	.0679	.0679	.0679
11.	Deferred Return	L5 * L9	142941	161898	198879	205437	212057	218721	225412
12.	Cash Return	L5 * L10	263330	252238	225065	232486	239977	247520	255091
13.	Book Depreciation	OCA-2-25b.7 L5	81448	81448	81448	81448	81448	81448	81448
14.	Tax Exempt Return	OCA-2-25b.7 L16-L19	192018	180474	170127	160799	152336	144146	135955
15.	Taxable Return	L12 - L14	71312	71764	54938	71687	87641	103374	119136
16.	Taxable Depreciation	L7 - L13	0	3762	8137	13662	19531	25768	32396
17.	Taxable Return + Deprcatn	L15 + L16	71312	75526	63075	85349	107172	129142	151532
18.	Income Taxes	L17 * 1.0462	74607	79015	65989	89292	112123	135108	158533
19.	Total Revenue Requirement	L7 + L12 + L18	419385	416463	380639	416888	453079	489844	527468

PHILADELPHIA ELECTRIC COMPANY

Illustration of Trended Rate Base on Limerick 1 Initial Investment

Line No.	Description	1993	1994	1995	1996	1997	1998	1999	2000	2001
1.	Initial Capital	3176476	3176476	3176476	3176476	3176476	3176476	3176476	3176476	3176476
2.	Accumulated Deferred Ret.	1365345	1597451	1836230	2081633	2333580	2591956	2856607	3127335	3403894
3.	Total Capital	4541821	4773927	5012706	5258109	5510056	5768432	6033083	6303811	6580370
4.	Accumulated Depreciation	673392	794280	922656	1058991	1203788	1357583	1520948	1694492	1878865
5.	Net Investment	3868429	3979647	4090050	4199118	4306268	4410849	4512135	4609319	4701505
6.	Remaining Life Years	32	31	30	29	28	27	26	25	24
7.	Remaining Life Depreciatn	120888	128376	136335	144797	153795	163365	173544	184373	195896
8.	Overall Return	.1279	.1279	.1279	.1279	.1279	.1279	.1279	.1279	.1279
9.	Inflation Rate	.06	.06	.06	.06	.06	.06	.06	.06	.06
0.	Cash Return Rate	.0679	.0679	.0679	.0679	.0679	.0679	.0679	.0679	.0679
1.	Deferred Return	232106	238779	245403	251947	258376	264651	270728	276559	282090
2.	Cash Return	262666	270218	277714	285120	292396	299497	306374	312973	319232
3.	Book Depreciation	81448	81448	81448	81448	81448	81448	81448	81448	81448
4.	Tax Exempt Return	127675	119575	111384	103194	99636	96077	92519	88960	80995
5.	Taxable Return	134991	150643	166330	181926	192760	203420	213855	224013	238237
6.	Taxable Depreciation	39440	46928	54887	63349	72347	81917	92096	102925	114448
7.	Taxable Return + Deprcatn	174431	197571	221217	245275	265107	285337	305951	326938	352685
8.	Income Taxes	182490	206699	231437	256607	277355	298520	320086	342043	368979
9.	Total Revenue Requirement	566044	605293	645486	686524	723546	761382	800004	839389	884107

PHILADELPHIA ELECTRIC COMPANY

Illustration of Trended Rate Base on Limerick 1 Initial Investment

Line No.	Description	2002	2003	2004	2005	2006	2007	2008	2009	2010
1.	Initial Capital	3176476	3176476	3176476	3176476	3176476	3176476	3176476	3176476	3176476
2.	Accumulated Deferred Ret.	3685984	3973246	4265254	4561509	4861432	5164355	5469510	5776021	6082892
3.	Total Capital	6862460	7149722	7441730	7737985	8037908	8340831	8645986	8952497	9259368
4.	Accumulated Depreciation	2074761	2282922	2504140	2739263	2989199	3254921	3537472	3837973	4157631
5.	Net Investment	4787699	4866800	4937590	4998722	5048709	5085910	5108514	5114524	5101737
6.	Remaining Life Years	23	22	21	20	19	18	17	16	15
7.	Remaining Life Depreciatn	208161	221218	235123	249936	265722	282551	300501	319658	340116
8.	Overall Return	.1279	.1279	.1279	.1279	.1279	.1279	.1279	.1279	.1279
9.	Inflation Rate	.06	.06	.06	.06	.06	.06	.06	.06	.06
10.	Cash Return Rate	.0679	.0679	.0679	.0679	.0679	.0679	.0679	.0679	.0679
11.	Deferred Return	287262	292008	296255	299923	302923	305155	306511	306871	306[illegible]
12.	Cash Return	325085	330456	335262	339413	342807	345333	346868	347276	346[illegible]
13.	Book Depreciation	81448	81448	81448	81448	81448	81448	81448	81448	81448
14.	Tax Exempt Return	77620	74245	70870	67496	64128	64051	60493	56935	53376
15.	Taxable Return	247465	256211	264392	271917	278679	281282	286375	290341	293032
16.	Taxable Depreciation	126713	139770	153675	168488	184274	201103	219053	238210	258668
17.	Taxable Return + Deprcatn	374178	395981	418067	440405	462953	482385	505428	528551	551700
18.	Income Taxes	391465	414275	437382	460752	484341	504671	528779	552970	577189
19.	Total Revenue Requirement	924711	965949	1007767	1050101	1092870	1132555	1176148	1219904	1263713

PHILADELPHIA ELECTRIC COMPANY

Illustration of Trended Rate Base on Limerick 1 Initial Investment

Line No.	Description	2011	2012	2013	2014	2015	2016	2017	2018	2019
1.	Initial Capital	3176476	3176476	3176476	3176476	3176476	3176476	3176476	3176476	3176476
2.	Accumulated Deferred Ret.	6388996	6693060	6993649	7289151	7577758	7857444	8125943	8380718	8618933
3.	Total Capital	9565472	9869536	10170125	10465627	10754234	11033920	11302419	11557194	11795409
4.	Accumulated Depreciation	4497747	4859727	5245097	5655516	6092799	6558943	7056163	7586945	8154123
5.	Net Investment	5067725	5009809	4925028	4810111	4661435	4474977	4246256	3970249	3641286
6.	Remaining Life Years	14	13	12	11	10	9	8	7	6
7.	Remaining Life Depreciatn	361980	385370	410419	437283	466144	497220	530782	567178	606881
8.	Overall Return	.1279	.1279	.1279	.1279	.1279	.1279	.1279	.1279	.1279
9.	Inflation Rate	.06	.06	.06	.06	.06	.06	.06	.06	.06
10.	Cash Return Rate	.0679	.0679	.0679	.0679	.0679	.0679	.0679	.0679	.0679
11.	Deferred Return	304064	300589	295502	288607	279686	268499	254775	238215	218[illegible]
12.	Cash Return	344099	340166	334409	326607	316511	303851	288321	269580	247[illegible]
13.	Book Depreciation	81448	81448	81448	81448	81448	81448	81448	81448	81448
14.	Tax Exempt Return	49818	46259	42701	39142	35584	32025	28467	24908	21350
15.	Taxable Return	294281	293907	291708	287465	280927	271826	259854	244672	225893
16.	Taxable Depreciation	280532	303922	328971	355835	384696	415772	449334	485730	525433
17.	Taxable Return + Deprcatn	574813	597829	620679	643300	665623	687598	709188	730402	751326
18.	Income Taxes	601369	625449	649354	673020	696375	719365	741952	764147	786037
19.	Total Revenue Requirement	1307448	1350985	1394182	1436910	1479030	1520436	1561055	1600905	1640161

PHILADELPHIA ELECTRIC COMPANY

Illustration of Trended Rate Base on Limerick 1 Initial Investment

Line No.	Description	2020	2021	2022	2023	2024	2025
1.	Initial Capital	3176476	3176476	3176476	3176476	3176476	3176476
2.	Accumulated Deferred Rat.	8837410	9032583	9200432	9336389	9435185	9435185
3.	Total Capital	12013886	12209059	12376908	12512865	12611661	12611661
4.	Accumulated Depreciation	8761004	9411580	10110950	10866269	11689567	12611661
5.	Net Investment	3252882	2797479	2265958	1646596	922094	0
6.	Remaining Life Years	5	4	3	2	1	0
7.	Remaining Life Depreciatn	650576	699370	755319	823298	922094	0
8.	Overall Return	.1279	.1279	.1279	.1279	.1279	.1279
9.	Inflation Rate	.06	.06	.06	.06	0	0
10.	Cash Return Rate	.0679	.0679	.0679	.0679	.1279	.1279
11.	Deferred Return	195173	167849	135957	98796	0	0
12.	Cash Return	220871	189949	153859	111804	117936	0
13.	Book Depreciation	81448	81448	81448	81448	81448	0
14.	Tax Exempt Return	17791	14233	10674	7116	3558	0
15.	Taxable Return	203080	175716	143185	104688	114378	0
16.	Taxable Depreciation	569128	617922	673871	741850	840646	0
17.	Taxable Return + Deprcatn	772208	793638	817056	846538	955024	0
18.	Income Taxes	807884	830304	854804	885648	999146	0
19.	Total Revenue Requirement	1679331	1719623	1763982	1820750	2039176	0

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SECRETARY'S OFFICE
Public Utility Commission

Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission

Pennsylvania Public Utility Commission, et al.

vs.

Philadelphia Electric Company

PA P.U.C. Docket No. R-850152

DOCKETED
FEB 26 1986

Direct Testimony

of the

Pennsylvania Business Utility Users Group

FOLDER

Witness: Robert L. Figley

Filed: January 22, 1986

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

A. My name is Robert L. Figley. My business address is 1220 L Street, N.W., Washington, D.C. 20005. I am a senior consultant with the economic consulting firm of Snavely, King & Associates, Inc.

Q. Will you briefly describe Snavely, King & Associates, Inc.?

A. Snavely, King & Associates, Inc. was formed in April 1970 to conduct research on a consulting basis into economic issues of costs, revenues, rates, and demand characteristics of regulated utilities. Most of the firm's work has involved the preparation and presentation of expert testimony before federal and state regulatory agencies.

Q. Have you attached a description of your personal background, experience and qualifications?

A. Yes. Attachment A is a brief summary of my background and experience. Attachment B is a tabulation of my appearances before state and federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Pennsylvania Business Utility Users Group (PBUUG) which is an informal association of leading general merchandise retail store chains in the Philadelphia area.

Q. What is the objective of your testimony?

A. My colleague, Charles W. King, appearing on behalf of PBUUG, has recommended that the capital costs of Limerick be allocated among customer classes according to both the energy and the demand factors of the respective classes. The first objective of my testimony is to describe the procedure I used to implement Mr. King's recommendation. A summary of the

class cost of service based on Mr. King's proposal is presented in Exhibit RLF-1. I then address issues of class revenue distribution and rate structure which emanate from this revised class cost of service. Finally, I will discuss the efficacy and efficiency of Philadelphia Electric Company's (PECO) use of a ratchet provision in its High Tension (HT) and Primary Distribution (PD) rate schedules for determining individual customer monthly billing.

Class Cost of Service

Q. Mr. King's testimony conceptualized the allocation of Limerick 1 costs based on demand and energy considerations. Please describe the procedure you used to implement his recommendation.

A. I based my recast of the class cost of service entirely on the Company's class cost of service study, Exhibit WFS-1. Thus, WFS-1 constitutes the basic cost document into which I incorporated Mr. King's proposals.

The single most important change I made to WFS-1 was the revision of the Company's allocation of nuclear production plant (Accounts 320-325) to reflect the separation of Limerick 1 costs into energy and demand components. The total capital cost of Limerick 1 in WFS-1 is $3.82 billion. I calculate the portion of Limerick costs attributable to meeting growth in system peak load to be $417.8 million based upon the 1986 cost of a peaker generating unit as calculated by Potomac Electric Power Company ($396/kw x 1055 mw).[1/] This portion of Limerick's cost was then allocated to customer

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1/ Based on information solicited from Potomac Electric Power Company (Edward R. Mayberry) used in the development of marginal costs.

classes based upon the ratio of class contributions to the system's average of four summer coincident peaks (Factor A-1, WFS-1). The residual of Limerick's costs totaling $3402.2 million or 89.06 percent of the unit's total investment was then distributed to customer classifications using the class energy allocation factors in WFS-1 (Factor C-1). The Company's allocation of the residual of the nuclear plant costs as well as other production plant costs included in WFS-1 was not disturbed. This reassignment of investment produced changes in other class allocation factors internal to the Company cost of service program. For example, allocation factors F-1, F-4 and F-5, which relate to various summaries of plant investment, all changed as a result of the revision in class cost responsibility for nuclear production plant costs. In turn, these changes required various expense reallocations.

Q. Does your class cost of service reflect other changes in cost allocation?

A. Yes. I also reallocated certain costs that are specifically and directly related to Limerick 1. These costs included Limerick 1 related costs for Accumulated Provision for Depreciation (WFS-1, page 23), Liberalized Depreciation (WFS-1, page 24) and Depreciation Expense Production (WFS-1, page 16). For each of these major accounts where Limerick 1 costs were separately stated, I allocated 89.06 percent to customer classifications based on the energy coefficients (C-1). The residual of the Limerick-specific costs, together with the remaining balance of the accounts, were then allocated to classes based on the revised F-1 and/or F-4 class coefficients.

Q. Have you developed a summary of this reallocation?

A. Yes. Exhibit RLF-1 is identical to the summary pages of PECO's class cost of service, Exhibit WFS-1. It shows my revised class cost of service and rate of return under present rates and under PECO's proposed distribution of the requested rate increase (lines 32 and 35).

Q. Are there significant differences in class rate of return produced between the Company's 4-CP method and Mr. King's proposal (hereafter referred to as the PBUUG method)?

A. Exhibit RLF-2 compares the class rates of return under the two allocation methods. It shows that the most significant change in rate of return is for the lighting services and rate OP. Exhibit RLF-3 shows the class 4-CP and energy production plant allocation factors used in the PECO and PBUUG cost of service studies. Under the PECO method all production plant is allocated to classes using only the classes' respective 4-CP ratio. As shown in Exhibit RLF-3, virtually no cost responsibility for production costs would be allocated to the lighting services and rate OP. Under the PBUUG allocation method, lighting services are allocated a portion of the Limerick cost based upon their relative share of system energy consumption. As a consequence, their respective cost responsibilities under the PBUUG method increase and the rate of return decreases.

Class Revenue Allocation

Q. Based upon the class rate of return produced in the PBUUG study, do you endorse the PECO class rate increase recommendations?

A. No. I support the underlying objective of moving all classes toward the average rate of return as articulated by Mr. Williams. The Company's revenue distribution recommendations were not, however, designed

using the PBUUG cost of service. Therefore, as shown on line 36 of Exhibit RLF-1, several rate design objectives advocated by Mr. Williams are not accomplished using his class rate distribution plan notably the goal of establishing the initial SEPTA and AMTRAK rates at the system average rate of return. Similarly, the SLP service would not, under the PBUUG cost of service, qualify for a rate increase equal to projected fuel savings as proposed by Mr. Williams. Therefore, other considerations aside, I believe some adjustment to Mr. Williams' class rate increase recommendations are required.

Q. Please describe your recommended distribution of the net base revenue increase.

A. Exhibit RLF-4 summarizes my proposals for class rate adjustments. I have adopted Mr. Williams' recommendation that the SEPTA and AMTRAK rates of return should equal the proposed system average. For the other classes, including the lighting and off-peak classes, I recommend the system average rate increase. With respect to SEPTA and AMTRAK. I determined the base rate and fuel roll-out (included in cost of service) revenues required to achieve this objective. The aggregate base rate increase required for these services is $8,930,700. This total was backed out of the base rate increase of $670,679,000. The residual net base rate revenue requirement of $661,748,000 was then applied to the proforma class base revenue on an equal percentage (28.694%) basis to produce the class net base rate increase shown on my exhibit.

Q. Is this the procedure you have previously recommended to regulatory commissions for determination of class revenue requirement?

A. No. Ordinarily my recommendation to regulatory commissions, considering the distribution of additional system revenue, is that class rate increases be set so as to move the rates of return for all classes into a predetermined tolerance band of acceptability, e.g., plus or minus 10 percent of the system average. In my opinion, a plus or minus 10 percent band is acceptable as it allows for consideration of non-cost factors in ratemaking. Generally, the procedure using a tolerance band approach requires allocation of a portion of the rate increase to classes that fall below the tolerance floor, and/or provide a credit for classes with returns in excess of the ceiling under present rates. The residual of the rate increase (total plus credits minus deficiency adjustments) is then spread to all classes on a uniform percentage basis.

Although as seen in Exhibit RLF-1 (line 39), the return index for all classes except the "Other Lighting" service do fall within a plus or minus 20 percent tolerance which Mr. Williams finds acceptable in this proceeding, I have not proposed using the tolerance band approach. Under a plus or minus 10 percent standard, which I would advocate, significant adjustments in class rates would be required before the average class rate increase could be determined. I believe, in this case, the very drastic adjustments that would be required are not justified.

Q. Why do you not recommend the tolerance band procedure in this case?

A. The 4-CP cost of service study produced by PECO is, in my opinion, not a reliable standard owing to the radical departure in class rates of return it produced as compared to historical patterns. As brought out in the cross-examination of PECO rate design witnesses (Williams and Sundermeir)

development of the A-1 (4-CP) class alloction factor is probably distorted owing to the inclusion of interruptible demand in the HT customer classification, and apparent failure by PECO to weather normalize the 1984 load data for the test year 1986. While it is true the exclusion of SEPTA and AMTRAK from the HT class in WFS-1 accounts for a small downward tilt in the HT rate of return (5.37 percent without SEPTA/AMTRAK, 5.51 percent with the service), no reason other than those cited above can explain the 84 percent of system average return under current rates experienced by the HT class in this test year vs. the historical pattern shown in Exhibit RLF-5. That exhibit demonstrates that since 1975 the HT class has consistently earned rates of return well above the system average. Similarly, the residential services rate of return index of 1.00 in WFS-1 is abnormally high relative to the historic returns derived from this service. Given the range of the HT and residential service classes rates of return departure from the norm in WFS-1, the most prudent course to follow in this proceeding is to spread the proposed increase on a relatively uniform percentage basis as presented in Exhibit RLF-4.

Rate Structure

Q. What is the proper relationships between cost of service and rate structure?

A. The purpose of the cost of service study is to determine the share of total costs that the Company should be recovering from each customer class. The Company should design its tariffs to fully recover each class's revenue requirement through the customer, demand, and energy charges. The recovery of allocated revenues from the customer, demand and energy

charges should track the allocation of these costs to the customer, demand and energy components in the cost of service study. Allocating the revenue requirement to these charges in the tariff in proportion to the allocation of costs to these components in the cost of service study is commonly referred to as cost-based tariff design.

Q. Have you produced rate structures consistent with this tenet?

A. Yes. Exhibit RLF-6 (two pages) shows my recommended rate designs for the High Tension (HT) and Primary Distribution (PD) rate charges.

Q. How were the various component charges in your proposed HT and PD tariffs developed?

A. PBUUG rate charges were developed in the same manner as those developed by PECO. Briefly, the first task in the procedure is to determine the distribution of cost responsibility for the class based on the allocation of demand, energy and customer-related costs to serve as shown in the PBUUG cost of service. The total revenue to be recovered from each rate component charge was then established and an annual unit cost per kw, kwh, and customer charge established. The procedure exactly duplicates the process as presented on page 39 of PECO Exhibit WFS-1.

Because the HT tariff is an hours-use rate structure, energy charges per kilowatt-hour were established at the three hours-use intervals. Total class costs to be recovered through the energy charges were then calculated based upon PECO's estimate of class energy sales as set forth in Company Exhibit IV-C-1, page 10, Parts 1 and 2. The total energy revenues to be recovered from the rate block energy charges were then subtracted from the total class revenue requirement (present rate revenue

times the recommended class increase of 28.694 percent -- Exhibit RLF-4). The residual of the class revenue requirement under the proposed rate class rate increase was then assigned for recovery through the monthly customer service charge and a flat kilowatt-hour charge, again in the same manner as described by Mr. Williams. The PBUUG rate proposed for PECO's Primary Distribution service follow the same procedure.

Q. Have you produced a proof of revenue calculation demonstrating the recovery of the service's cost to PECO?

A. Yes. Exhibit RLF-7 (two pages) makes such a demonstration.

Billing Ratchet

Q. Would you please describe PECO's ratchet?

A. Yes. A billing ratchet is a rate device applied to demand metered customers which collects the costs of the customer's peak demand throughout the year. The ratchet works by taking a specified percentage of the customer's annual peak demand and designating that level as the minimum kw to be billed in subsequent months. In PECO's case, an HT or PD customer's billing demand is either 80 percent of his maximum demand during the previous summer orhis actual demand, whichever is greater. This billing demand is used to establish both the demand charge and the hours' use blocks of the energy charge.

Q. Did PECO's rate design witnesses discuss the ratchet provision of proposed rate schedules HT and PD?

A. No. Mr. Williams' rate design testimony did not address this provision of the proposed HT and PD rates either with respect to the need for its continuation or the suitability of retaining the 80 percent minimum.

Q. Are you familiar with the rationale typically advanced in support of ratchet billing?

A. Yes. Utilities which use ratchet billing typically cite two reasons for imposing the rate provision. First, they contend that the ratchet furnishes the customer a pricing signal that the cost which he incurs is tied to his highest annual demand. Second, utilities argue that this billing provision provides a strong incentive to the customer to practice conservation.

Q. Do you have any comment regarding the first alleged justification for ratchet billing?

A. Yes. The implicit assumption of the billing demand ratchet is that an individual customer's peak demand is a valid representation of its impact on the Company's load growth and hence, the need to construct all peak related facilities -- generation, transmission and distribution. This proposition, however, does not account for the diversity between the individual customer's peak demand and that of the utility itself. The two may coincide, but on the other hand, they may not. Generation and transmission costs are allocated to HT and PD customer classifications based upon class demands at the time of PECO's system peak demand during each of the four summer months. It is unlikely that a customer's individual peak demand will correspond with those peak demands.

Even if this issue of customer diversity is overlooked, the importance of the peak demand price signal has diminished greatly. Conceivably, there might have been sufficient reason for the Company to recommend and the Commission to adopt the billing demand ratchet when it was

first introduced by the Company seven or eight years ago. At that time, PECO's peak was growing rapidly, its reserve margins were low, and it relied heavily on peaker generation to meet summer loads. A demand ratchet might arguably have furnished a reasonable approach to collect the costs of peak service from low load factor customers. With greatly reduced load growth and with the commercial operation of the Limerick 1's additional 1,055 mw of base load production, these arguments are no longer compelling.

Q. Does ratchet billing encourage customers to conserve?

A. No. To some extent it has the reverse incentive. It conveys the signal that all demands up to 80 percent of the customer's established summer peak are virtually cost-free. For example, if a customer experiences a maximum summer peak demand of 1,000 kilowatts, application of the 80 percent demand ratchet virtually invites that customer to establish his consumption pattern in subsequent months so as to reach but never exceed 800 kilowatts.

The effect on the energy blocking could discourage consumption if the ratchet places the customer just under one of the hours' use tailblocks. For example, if the demand ratchet places the customer at, say, 280 hours' use, he can squander only a small amount of additional power to qualify for the very low tailblock rate that begins at 300 hours' use. Furthermore, as long as he does not exceed 80 percent of his previous summer demand, it does not matter to him when he uses that power. He may thus increase use during the most costly hours of PECO's operation at no added cost.

Q. Has any commission concluded that demand ratchets are counter to the principle of conservation?

A. Yes. The Federal Energy Regulatory Commission disapproved a 95 percent demand ratchet on the grounds that it was "... incompatible with public policy toward energy conservation since it encourages the customers to increase their power sales, no matter how inefficient those uses, in order to utilize all of the demand they will pay for under the ratchet."[1/]

Q. To your knowledge, has any information been produced for the record to support continuation of ratchet billing?

A. No.

Q. What do you recommend with respect to the billing demand ratchet?

A. Unless PECO can produce a persuasive justification for the continuation of the demand ratchet under present conditions, I recommend it be eliminated.

Q. Has any information been provided by PECO that identifies the amount of revenue that is produced by the ratchet provision of the HT and PD rates?

A. No. In response to IR-UUC/UP-4-2, Mr. Williams sponsored the answer, "The revenue collected due to imposition of the ratchet is not known, since this would require calculation of each customer's bill, both with and without the ratchet.

1/ Carolina Power & Light Co., Docket No. ER76-495 Opinion 19, mimeo p. 18.

Q. If the ratchet provision was eliminated from the HT and PD rate rates, would there be an adverse impact to PECO's recovery of the classes' respective revenue requirements?

A. No. PECO would have the same opportunity to recover the HT and PD class revenue requirements by using actual metered determinants of usage. One result of eliminating the ratchet provision of the HT and PD rate tariffs would be the need to increase both the demand and the energy charges to compensate for the fewer units over which the revenue requirement is spread. Presumably, the higher demand charge applicable throughout the year could have a beneficial conservation impact on HT and PD customer requirements during both the summer and winter seasons.

Q. Does this conclude your testimony?

A. Yes, it does.

Philadelphia Electric Company
Class Cost of Service as Modified
Budget Year Ended 30 June 1986

LINE #	ITEM	TOTAL AMOUNT	HT	PD	SECDY	R-H	R	OP	SLP	SLS	ALL OTH LIGHT	OTHER UTIL	INTER DEPT	SEPTA	AMTRAK
1	TTL OPERATING REVENUE	2,290,779	796,223	181,215	332,676	123,681	714,533	24,342	13,463	17,742	2,327	29,885	4,840	18,448	31,404
	Revenue Deductions														
2	Oper. & Maint. Expense	1,440,907	538,912	118,880	183,963	78,242	451,475	16,874	6,618	6,836	1,018	13,713	2,619	10,849	19,517
3	Depr. & Other Amort.	264,877	101,816	21,221	33,583	14,793	76,583	3,883	1,617	2,644	261	3,539	518	2,134	3,165
4	Taxes Other Than Income	82,178	28,337	6,480	11,483	4,393	27,334	797	586	651	79	441	66	619	992
5															
6	Subtotal.....	1,787,962	669,065	136,581	228,949	97,428	555,392	20,754	8,741	10,131	1,358	17,693	2,603	13,593	23[redacted]
7	Income Taxes	34,832	(5,830)	2,350	20,216	4,821	3,216	2,841	1,188	1,686	340	1,113	376	1,836	2,281
	Provision for Deferred Income Tax														
8	Liberalized Depreciation	124,755	45,977	10,880	16,343	6,724	38,462	1,883	843	1,844	184	1,593	237	971	1,364
9	Deferred Fuel	(156,762)	(72,118)	(12,887)	(19,431)	(8,998)	(36,341)	(2,203)	(538)	(339)	(88)	0	0	(1,496)	(2,483)
10	Nuclear Fuel Costs	(4,121)	(1,814)	(335)	(516)	(239)	(964)	(58)	(14)	(9)	(2)	(63)	(9)	(38)	(68)
11	Production Facilities	67,561	28,012	6,274	9,574	2,648	18,667	2	3	0	0	1,868	147	521	785
12	Certain Capital Costs	9,577	3,538	774	1,255	516	2,953	77	65	88	8	123	18	75	105
13	Production Facilities	(12,633)	(5,249)	(1,173)	(1,790)	(495)	(3,498)	8	(1)	0	0	(188)	(27)	(97)	(132)
14	Amortization of FIT % Charge	(973)	(359)	(79)	(127)	(52)	(388)	(8)	(6)	(8)	(1)	(12)	(2)	(8)	(11)
15	Investment Tax Credit - Net	(3,481)	(1,253)	(275)	(446)	(183)	(1,849)	(27)	(23)	(28)	(3)	(44)	(6)	(27)	(37)
16	Gain for Desposition of Property	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Total.....	1,845,997	659,970	143,390	254,027	101,370	576,546	21,581	10,258	12,557	1,716	21,233	3,337	14,530	25,486
18	Operating Income After Income Taxes	444,781	136,253	37,825	78,649	22,311	137,987	2,761	3,205	5,185	611	8,652	1,503	3,918	5,918
	Rate Base														
19	Electric Plant in Service Incl. Common	8,893,834	3,262,721	715,526	1,164,871	488,185	2,762,437	71,319	59,788	74,869	7,388	113,840	16,819	68,863	96,896
20	Total.....	8,893,834	3,262,721	715,526	1,164,871	488,185	2,762,437	71,319	59,788	74,869	7,388	113,840	16,819	68,863	96[redacted]
21	Accumulated Provision for Depreciation	1,665,850	536,980	127,867	218,876	98,684	583,313	15,369	17,361	24,213	2,158	18,548	2,815	12,030	16,436
22	Depreciation Utility Plant	7,227,984	2,725,741	588,459	953,195	381,421	2,179,124	55,950	42,427	49,856	5,222	95,292	14,004	56,833	80,450
23	Working Capital	272,153	103,761	21,150	34,599	14,846	82,312	3,282	1,223	1,289	188	3,388	491	2,095	3,617
24	Depr. Util. Plant & Work. Capital...	7,500,137	2,829,502	609,609	987,794	396,267	2,261,436	59,232	43,650	51,865	5,410	98,672	14,495	58,928	84,077

Philadelphia Electric Company
Class Cost of Service as Modified
Budget Year Ended 30 June 1986

LINE #	ITEM	TOTAL AMOUNT	HT	PD	SECDY	R-H	R	OP	SLP	SLS	ALL OTH LIGHT	OTHER UTIL	INTER DEPT	SEPTA	AMTRAK
	LESS														
	Accumulated Deferred Income Tax														
25	Accumulated Amortization incl. Income Tax	2,323	993	282	389	114	591	17	4	3	1	35	5	20	29
26	Liberalized Depreciation	526,166	202,544	42,566	69,219	28,851	153,249	4,972	3,158	3,656	485	7,856	1,833	4,256	6,291
27	Recoverable Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Customer Advances & Deposits	8,116	739	401	953	667	4,538	118	254	354	29	0	0	40	31
29	PA Water & Power Refund	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Investment Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Total Rate Base.....	6,963,532	2,625,226	566,440	918,313	366,635	2,103,866	54,125	48,234	47,852	4,975	91,581	13,457	54,612	[redacted]
	Rates of Return														
32	After Income Taxes	6.387	5.190	6.678	8.565	6.885	6.561	5.101	7.966	11.822	12.281	9.447	11.169	7.174	7.685
33	Index	100.000	0.812	1.045	1.340	0.932	1.027	0.798	1.247	1.725	1.920	1.478	1.748	1.123	1.981
	Full Year Effect of Rate Change														
34	Operating Income	884,369	312,129	74,889	142,527	45,345	270,928	4,222	3,567	5,410	664	8,654	1,503	6,381	8,236
35	Rate of Return	12.70	11.89	13.21	15.52	12.36	12.88	7.80	8.87	11.50	13.35	9.45	11.17	11.68	10.58
36	Index	1.000	0.936	1.040	1.222	0.974	1.014	0.614	0.698	0.905	1.051	0.744	0.879	0.920	0.833
	Full Year Effect of PSUG Rate Change														
37	Operating Income	884,369	308,172	73,878	140,904	47,097	267,467	7,899	5,708	5,410	857	8,652	1,503	6,936	9,883
38	Rate of Return	12.70	11.74	13.04	15.34	12.85	12.72	14.59	14.19	11.50	17.23	9.45	11.17	12.70	12.70
39	Index	100.000	92.440	1.027	1.208	1.012	1.002	1.149	1.117	90.530	1.357	0.744	0.879	100.000	100.000

PHILADELPHIA ELECTRIC COMPANY

Class Rate of Return
Under Present Rates
for Test Year Ended June 30, 1986

	4-CP Method 1/		PBUUG Method 2/	
	Rate of Return	Index	Rate of Return	Index
HT	5.37%	.840	5.19%	.812
PD	6.21	.972	6.68	1.045
SECDY	8.07	1.279	8.57	1.340
R-H	7.39	1.157	6.09	.952
R	6.14	.961	6.56	1.027
OP	21.95	3.435	5.10	.798
SLP	11.12	1.755	7.97	1.247
SLS	13.15	2.058	11.02	1.725
OL	18.95	2.966	12.28	1.92
OU	9.55	1.495	9.45	1.478
Inter D	11.16	1.747	11.17	1.748
SEPTA	7.86	1.230	7.17	1.123
AMTRAK	9.23	1.444	7.61	1.901
System	6.39	1.000	6.39	1.000

1/ WFS-1.

2/ Exhibit RLF-1.

PHILADELPHIA ELECTRIC COMPANY

Leading Cost Allocation Factors

	Ratio 1/	
	A-1 (4-CP)	C-1 (Energy)
HT	.41462	.44002
PD	.09286	.08123
SECDY	.14172	.12513
R-H	.03919	.05795
R	.27630	.23403
OP	.00003	.01418
SLP	.00005	.00345
SLS	.00001	.00218
OL	.00000	.00057
OU	.01492	.01529
Inter D	.00217	.00218
SEPTA	.00771	.00913
AMTRAK	.01043	.01466
	1.00000	1.00000

1/ Exhibit WFS-1.

PHILADELPHIA ELECTRIC COMPANY

PBUUG Class Revenue Recommendation
Base Rate Revenue (000)

	Current Rates	Increase	Percent Increase	Proposed Net Base Revenue
R	$ 739,467	$212,182	28.69%	$ 951,649
R-H	127,424	36,563	28.69	163,987
OP	25,989	7,457	28.69	33,446
POL	1,527	438	28.69	1,965
GS	344,838	98,948	28.69	443,786
PD	191,010	54,808	28.69	245,818
HT	860,983	247,050	28.69	1,108,033
AMTRAK	31,683	4,816	15.20	36,499
SEPTA	20,100	4,115	20.47	24,215
SLP	14,993	4,302	28.69	19,295
SLS	18,129	--	0	18,129
TL	3,486	--	0	3,486
BLI	7	--	0	7
TRR	306	--	0	306
Total	$2,379,942	$670,679	28.12	$3,050,621

PHILADELPHIA ELECTRIC COMPANY

Historical Rate of Return (Index)
for HT and Residential Service
1975 - 1984

Rate of Return Index

Year	HT	Residential
1975	1.01	.82
1976	1.01	.80
1978	1.04	.81
1979	1.14	.71
1981	1.20	1.14
1982	1.19	.59
1983	1.15	.65
1984	1.20	.61

Source: PAIEUG Exhibit 1, Schedule 7 in Docket No. R-842590.

PHILADELPHIA ELECTRIC COMPANY

PBUUG Proposed High Tension Rate

Customer Charge	$230.20/monthly
Demand	$ 6.18/kw
Energy	
First 150 hours use	$.0928
Next 150 hours use	.0733
Additional	.0541

PHILADELPHIA ELECTRIC COMPANY

PBUUG Proposed Primary Distribution Rate

Customer Charge	$263.65/monthly
Demand	$ 5.83/kw
Energy	
First 150 hours use	$.1030
Next 150 hours use	.0823
Additional	.0620

PHILADELPHIA ELECTRIC COMPANY

Proof of Revenue
PBUUG Proposed Rate HT

		Bills, Kw and Kwh from Sample	Present Pricing	Present Revenue	Proposed Pricing	Proposed Revenue
Customer Charge	(Bills)	27,596	$220.45	$ 6,083,538	$230.20	$ 6,352,598
All Kw	(Kw)	27,682,384	5.37	148,654,402	6.18	171,077,133
Kwh						
1st 150 hrs	(Kwh)	4,133,193,716	0.0739	305,443,016	.0928	383,560,377
next 150 hrs	(Kwh)	3,815,618,298	0.0556	212,148,377	.0733	279,684,821
addl use	(Kwh)	4,431,005,022	0.8376	166,605,789	.0541	239,717,372
Subtotal				838,935,122		1,080,392,301
High Volt. Disc (7 largest)		2,527,620	.30	- 758,286	.30	- 758,286
High Volt. Disc >66 kv				- 22,128		- 22,128
High Volt. Disc -66 kv				- 81,385		- 81,385
High Volt. Disc -33 kv				- 606,481		- 606,481
				837,466,842		1,078,924,021
Unaccounted for				99,292		127,156
				837,566,134		1,079,051,177
Proforma Base Rev. Excl. NSR				844,700,874		1,088,188,085
Night Service Rider				3,520,126		3,520,126
TTL Proforma Base Revenue				848,221,000		1,091,708,211
Less Curtailment Rider				- 113,000		- 113,000
Adj. Base Rev. 12-mos ended 6/30/85				848,108,000		1,091,595,211
TTL Base Rev				860,983,000		1,108,146,688
Curtailment R				0		- 113,000
Adj. Base Rev. 12-mos ended 6/30/86				860,983,000		1,108,033,688

PHILADELPHIA ELECTRIC COMPANY

Proof of Revenue
PBUUG Proposed Rate PD

	Bills, Kw and Kwh from Sample	Present Pricing	Present Revenue	Proposed Pricing	Proposed Revenue
Customer Charge	30,890	$253.96	$ 7,844,824	$263.65	$ 8,144,149
Kw	6,005,667	5.21	31,289,525	5.83	35,013,039
Kwh					
1st 150 hrs	891,063,406	.0805	71,730,604	.1030	91,779,531
next 150 hrs	687,608,080	.0600	41,256,485	.0823	56,590,145
addl use	400,339,444	.0398	15,933,510	.0620	24,821,046
Subtotal			168,054,948		216,347,910
Unaccounted for			143,343		185,535
Base Revenue			168,198,291		216,533,445
Proforma Base Excl. NSR			169,959,115		218,800,277
NSR			261,885		261,885
TTL Proforma Base Revenue			710,221,000		219,062,162
12-mos ended 6/30/86 Proforma Base Revenue			191,010,000		245,816,107

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Testimony and Exhibits

of

MELVIN P. BLOOM

On behalf of the

Philadelphia Area Industrial Energy User Group

(Allied Corporation, Fibers Division;
Boeing Vertol Company;
B.P. Oil, Inc.;
The Budd Company;
Liquid Air Corporation of North America;
Lukens Steel Company;
Nabisco Brands, Inc.;
SDC (a/Burroughs Company);
Smith Kline Beckman Corporation;
Sun Refining and Marketing Company;
3M Company)

and

United States Steel Corporation

January 1986
Project 4035

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

Before the

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of

PHILADELPHIA ELECTRIC COMPANY

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Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Testimony of Melvin P. Bloom

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Melvin P. Bloom, 1801 N. Front Street, Harrisburg, Pennsylvania.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation with the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A This is set forth in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Philadelphia Area Industrial Energy User Group (PAIEUG) and U.S. Steel Corporation, all of whom are large high-tension (Rate HT) customers of the Philadelphia Electric Company (the "Company" or "PECO").

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A The following is a summary of my recommendations:

(1) A properly developed coincident peak (4CP) cost-of-service study should be used in this proceeding.

(2) PECO's 4CP cost-of-service study, Exhibit WFS-1, should be rejected because (i) it is based on abnormal weather conditions and (ii) it does not properly reflect the coincident peak demand of Rate HT due to the improper inclusion of non-firm Rate HT customers' demand [Exhibit MPB-1 ( ) and MPB-2 ( )].

(3) PAIEUG et al's adjusted 4CP cost-of-service study [Exhibit MPB-3 ( )], should be utilized (i) as a guide for distributing any rate increase, and (ii) in developing proposed tariff rate charges.

(4) The Company's use of a Bary curve analysis in Rates GS, PD and HT rate design should be rejected since it produces meaningless results due to PECO's mismatching of a coincident peak allocation method for class revenue requirements and an NCP allocation methodology for rate design.

(5) Should the Commission decide to have PECO utilize the Bary curve analysis for rate design then, for consistency and correctness, it should require that a properly developed NCP study be used as a guide to determine rate schedule revenue requirements [Exhibit MPB-4 ( )].

Q WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A I am testifying on the following subjects:

(1) Cost of service;

(i) Problems associated with PECO's cost of service, Exhibit WFS-1.

(ii) Adjustments to correct Exhibit WFS-1 for more normal conditions.

(iii) Alternative cost-of-service studies which are compatible with PECO's rate design philosophy.

(2) PECO's load characteristics; and

(3) The load and supply characteristics of the PJM Interconnected system.

Q WHAT EXHIBITS ARE YOUR SPONSORING?

A I am sponsoring the following exhibits:

Exhibit	Description
MPB-1	Rate of Return at Present Rates, 1974-1986.
MPB-2	EDH Values and Their Affects on the Characteristics of Rate Schedules R and GS.
MPB-3	EDH Adjusted 4CP Cost-of-Service Studies.
MPB-4	NCP Cost-of-Service Studies.

In addition I am sponsoring an analysis of PECO's load characteristics and PECO's load characteristics, and the load and supply characteristics of the PJM Inter connection system in Appendix B.

Cost of Service

Q PLEASE DESCRIBE PECO'S COST-OF-SERVICE STUDY.

A Mr. Sundermier, testifying on behalf of PECO, has presented the results of a fully-embedded cost-of-service study for the future test year, the 12 months ending June 30, 1986--Exhibit WFS-1. The method used by PECO to allocate production and transmission facilities is the four summer coincident peak demand method (the average of each rate schedule's contribution to the monthly peak demand of June, July, August and September). Each rate schedule's monthly coincident peak demand contribution is based upon its 1984 summer monthly peak adjusted by the ratio of annual 1986 projected

sales to annual 1984 sales. Load studies, weather adjusted to 1984 conditions, are used to develop the weekly average one-half hour by one-half hour loads for rate Schedules R (residential), RH (residential - heating), and GS (general service - secondary voltage). Actual one-half hour by one-half hour demand data are used to develop the four summer peak day load profiles for all other rate classifications.

Q WHAT COMMENTS DO YOU HAVE REGARDING PECO'S STUDY?

A I believe the study is unreliable because it utilizes data which is based upon abnormal weather conditions. This, in turn, has the effect of producing unrealistic results. Since the study produces unrealistic results, it should not be used (1) as a guide for distributing any rate increase or (2) in developing proposed tariff rate charges. In addition, the study contains an error in the coincident peak demand data for rate Schedule HT due to the inclusion of demand associated with the Supplemental Energy Provision of the Night Service Rider.

Q DO THE PROBLEMS YOU HAVE WITH PECO'S COST-OF-SERVICE STUDY REQUIRE THAT THE STUDY BE DISREGARDED?

A No. After making the appropriate adjustments to the applicable factors, the study can be used as a guide to assess cost-relatedness and modify, where appropriate, the Company's proposal to distribute the rate increase. Mr. Jeffry Pollock, my

colleague, will discuss this in his direct testimony.

Q HOW DO THE RESULTS OF THE CURRENT COST-OF-SERVICE STUDY COMPARE WITH RESULTS FROM PECO'S PRIOR STUDIES?

A Schedule 1 of Exhibit MPB-1 ( ) shows each rate schedule's present rate of return and the corresponding deviation from system average rate of return for PECO's cost-of-service studies developed from 1974 through the present. For Rate Schedules HT (high tension) and PD (primary voltage), for example, the deviation in rate of return has consistently been increasing--moving farther above cost--except in the current case. For Rate R the exact opposite occurs, i.e., the deviation from system average moves farther below cost--except in the current case.

Q PLEASE DESCRIBE HOW THE CURRENT STUDY UTILIZES UNREALISTIC DEMAND DATA FOR PECO'S WEATHER SENSITIVE RATE CLASSES.

A In developing projected 1986 loads, PECO first developed 1984 loads and adjusted these loads by the ratio of 1986 projected annual sales to 1984 sales. 1984 loads for the weather-sensitive rates, Rate Schedules R, RH and GS, are developed by weather-adjusting average week day loads which were obtained from the Company's load research developed during the period 1980 through 1983.

In general, the effective degree hour (EDH)* for each 1984

*EDH is a variable used by PECO to measure the effect of weather.

summer monthly peak day is used to adjust the load research data in order to develop each weather sensitive rate schedule's one-half hour by one-half hour load profile for each of the four monthly peak days in 1984. A review of the 1980 through 1985 EDH summer peak day data, as shown in Schedule 1 of Exhibit MPB-2 ( ), indicates that in 1984 the actual four summer peak day EDH values were abnormally low. For example, the July, August, September, and the four-month average EDH values for 1984 are all lower than corresponding EDH values in any other year.

Schedule 2 of Exhibit MPB-2 ( ) shows 1984 summer peak day EDH as a percent of 1980 through 1983 average and 1985 peak day EDH. This schedule illustrates that the 1984 average of June-September peak day EDH are approximately 30% lower than either the 1980 through 1983 four-month average or the 1985 June-September average EDH.

Q HOW DO SUMMER PEAK DAY EDH AVERAGES COMPARE WITH PECO'S NORMAL HOT PERIOD EDH OF 213?

A The four summer monthly peak day EDH average as a percent of hot period EDH of 213 EDH for the time periods described above are shown in Schedule 3 of Exhibit MPB-2 ( ). As can be seen, the 1984 EDH percentage deviation of 37.6 % (100.0% - 62.4%) is nearly twice as large as the next greatest percentage deviation of 18.8% (100.0% - 81.2%) for any of the other years.

Q HOW CAN THE EFFECT OF ABNORMAL WEATHER CONDITIONS BE REDUCED IN PECO'S COST-OF-SERVICE STUDY?

A The effect of abnormal weather can be reduced by developing a more normal weather-adjusted future test year. This can be accomplished by adjusting weather-sensitive rate class load research data to either (1) the 1980-1983 monthly peak day average EDH, (2) the 1985 monthly peak day EDH, or (3) typical hot period EDH of 213 EDH.

Q IS A WEATHER ADJUSTMENT PROPER?

A Yes, it is. First, the future test year cost-of-service study contains numerous adjustments to revenues, sales, expenses and costs based upon PECO's future test year budget. The load characteristics of the weather-sensitive classes, however, were abnormal in 1984 and have not been properly adjusted. The lack of proper adjustment to reflect normal conditions will produce aberrations to the output of the cost study. Thus, it is appropriate to apply weather adjustments for the Company's future test year to eliminate these known aberration.

Q PLEASE EXPLAIN HOW THE ABNORMAL 1984 SUMMER WEATHER CONDITIONS EFFECT THE COMPANY'S WEATHER-SENSITIVE RATE SCHEDULES' LOAD CHARACTERISTICS.

A Schedule 4 of Exhibit MPB-2 ( ) compares actual and indexed annual load factor and coincidence factor for Rate Schedules R and

GS for the following periods:

(1) 1980
(2) 1981
(3) 1982
(4) 1980 through 1982 average
(5) 1984

The indexed load factors and coincidence factors are obtained by dividing yearly annual load factor or coincidence factor by corresponding 1980-1982 average values. This schedule shows that historical load factors and coincidence factors are quite similar but 1984 values were significantly different. For Rate Schedule R, for example, the 1984 load factor is 25% higher than the historical average and the 1984 coincidence factor is 19% lower.

Q WHAT EFFECT DO YOUR WEATHER ADJUSTMENTS HAVE ON THE 1984 ANNUAL LOAD FACTOR AND COINCIDENCE FACTOR FOR RATE SCHEDULES R AND GS?

A The effect of weather adjusting the abnormal 1984 weather conditions to more normal conditions is quite significant. Schedule 5 of Exhibit MPB-2 ( ) compares actual and indexed 1984 weather adjusted annual load factors and coincidence factors for Rate Schedules R and GS. The index is developed by dividing each weather adjusted load factor or coincidence factor by the actual 1980-1982 average value. Regardless of the type of weather adjustment, it is seen that the effect of properly adjusting the 1984 data is to produce a set of characteristics which are now consistent with historic values. This is yet another example of the need for and the appropriateness of the weather adjustment.

Q ON TR. 1714, MR. SUNDERMIER INDICATED THAT IT WAS NOT NECESSARY TO EXPLICITLY CORRECT 1984 WEATHER CONDITIONS SINCE 1986 PROJECTED (NORMAL WEATHER) KWH WERE USED IN THE COMPANY'S COST-OF-SERVICE STUDY. PLEASE COMMENT.

A Mr. Sundermier is wrong. For the future test year PECO has projected a load factor for Rate R of 42.3%--a value which is nearly equal to the abnormal 1984 value of 43.8%, and is 21% greater than the 1980-1982 average value. For Rate GS, the future test year load factor is projected to be 53.9%--a value which is close to the 1984 value of 56.1% but is 9% greater than the 1980-1982 average value.

Q WHAT OTHER ADJUSTMENT ARE YOU PROPOSING FOR PECO'S COST-OF-SERVICE STUDY?

A I am proposing a reduction of Rate HT's A-1 demand allocation factor by 32,539 kW. This adjustment, which is quite conservative, consists of the following:

(1) PECO included the coincident demand associated with the Supplemental Energy Provision for Rate HT Customer No. 3 for two of the four summer monthly peak days and did not include <u>any</u> revenue for <u>any</u> customer utilizing this provision; and

(2) Rate HT Customer No. 5 began service on the Supplemental Energy Provision in October, 1984. Since we are dealing with a future test year, it is appropriate to adjust this customer's monthly summer peak day demand downward to firm demand levels.

Q WHY DO YOU BELIEVE THIS ADJUSTMENT IS CONSERVATIVE?

A I believe the adjustment is conservative for the following reasons:

(1) For both Rate HT customers, I have used billing demand as a proxy for the customer's actual monthly peak demand contribution. If diversity would be taken into account, the adjustment would have been greater; and

(2) I have not accounted for the Rate HT Curtailment Rider customers' coincident peak demands which are included in Rate HT's A1 demand allocation factor.

Mr. Pollock will discuss the proper treatment of Rate HT Supplemental Energy Provision and Curtailable Rider customers' non-firm demand in his direct testimony.

Q HAVE YOU RERUN PECO'S COST-OF-SERVICE STUDY WITH THE ADJUSTMENTS DESCRIBED ABOVE?

A Yes, I have. The results are shown in Schedules 1 through 3 of Exhibit MPB-3 ( ). The following is a description of the weather adjustments made in each rerun:

Schedule	EDH Adjustment
1	1980 through 1983 average peak day EDH used.
2	1985 peak day EDH used.
3	213 EDH for each peak day used.

In addition, the A-1 demand allocation factor for Rate HT was reduced by 32,539 kW to reflect the Supplemental Energy Provision problems discussed above.

Q PLEASE DESCRIBE THE RESULTS OF YOUR ANALYSIS.

A The results of my analysis are summarized in Schedule 4 of Exhibit MPB-3 ( ). This schedule tabulates rate of return and revenue subsidy for each rate schedule under each weather adjustment scenario at present and proposed rates. As can be seen, the results of each of the EDH adjustments produce similar results.

Q WHAT IS A REVENUE SUBSIDY?

A A revenue subsidy is the amount of revenue which must be (1) added to a rate schedules' revenue requirement if the rate of return of that rate schedule is below the system-wide average rate of return, or (2) subtracted from a rate schedules' revenue requirement if the rate of return of that rate schedule is above the system-wide average rate of return in order to have all rate schedules produce the system-wide average rate of return.

Q HAVE YOU PREPARED ANY ADDITIONAL COST-OF-SERVICE STUDIES?

A Yes. I have developed a set of non-coincident peak (NCP) cost-of-service studies. The results of these studies are summarized in Schedules 1 through 4 of Exhibit MPB-4 ( ).

Q WHAT IS AN NCP COST-OF-SERVICE STUDY?

A An NCP cost-of-service study is a cost study which allocates production and transmission facilities on the basis of each rate class's maximum noncoincident peak demand.

Q WHY HAVE YOU DEVELOPED THESE NCP STUDIES?

A PECO uses a "Bary curve analysis" to develop the demand and energy charges in its commercial/industrial rates. The application of the Bary curve is described in detail in "Operational Economics of Electric Utilities" by C. W. Bary, Columbia University Press (1965). In his text, Mr. Bary develops a General Unified Theory regarding the design of electric rates which reflect load diversity. On Page 58 of his text, Mr. Bary, in discussing the distribution of load diversity benefits, states:

> The one (allocation method) which is farthest from meeting the requirements of the General Unified Theory is the so-called System Peak Responsibility, which reflects the demand-cost assignment to individual components on the basis of their loads at the time of the system peak load. This method reflects little conceptual perception of the nature and the mutual benefits of load diversity. . . .
>
> * * *
>
> . . . (O)nly the well known Noncoincident Peak (NCP) method, as will be shown in this chapter, conforms to that theory in the practical aspects of its application to the operation of modern electric utilities, because it is but a simplification of the method developed to conform to the concepts of the General Unified Theory . . . .

From the above it is clear that if PECO desires to utilize the Bary curve analysis for commercial/industrial rate design, it must also use an NCP cost-of-service study in order to adhere to Mr. Bary's General Unified Theory. To pick and choose as PECO has done produces meaningless results.

Q DURING CROSS-EXAMINATION, DIDN'T MR. SUNDERMIER INDICATE THAT

PECO'S 4CP METHOD WAS CONSISTENT WITH MR. BARY'S APPROACH SINCE AFTER ALLOCATING COSTS (USING THE 4CP METHOD), THE DEMAND-RELATED REVENUE REQUIREMENT ($/kW) WAS DEVELOPED BY DIVIDING THE 4CP DEMAND REVENUE REQUIREMENT BY THE RATE CLASS'S NONCOINCIDENT DEMAND?

A Yes, but he is wrong. The only way he can be correct is when the demand revenue requirements using the 4CP and the NCP cost studies are identical, which is not the case here.

Q EARLIER YOU INDICATED THAT A MISMATCH OF THE 4CP DEMAND ALLOCATION STUDY WITH THE BARY CURVE ANALYSIS PRODUCES MEANINGLESS RESULTS. PLEASE EXPLAIN.

A On Pages 47 through 54 of Section VII of WFS-1, PECO presented a set of cost-revenue curves for Rate Schedule HT and PD. Each of these curves, drawn for a different assumed monthly maximum demand level, indicates that the revenue curve at proposed rates is always above the cost curve which is developed at the system average rate of return at proposed rate levels. This relationship exists regardless of the level of maximum demand or hours of use. In other words, PECO's curves imply that the return from Rates PD and HT are always above system average--a direct contradiction to the results shown in PECO's cost-of-service study--which was used to develop the unit costs which were then used to generate the cost curves!

Q IN PECO'S 1977 RATE CASE AT DOCKET RID 438, THE COMMISSION ORDERED

THE COMPANY TO RESTRUCTURE RATES PD AND HT SO AS TO ELIMINATE, TO THE EXTENT REASONABLY POSSIBLE, VARIATIONS IN RATES OF RETURN FROM CUSTOMERS WITHIN THOSE CLASSES. DO THE COST VS. REVENUE CURVES SHOWN IN SECTION VII OF EXHIBIT WFS-1 COMPLY WITH THE COMMISSION"S DIRECTIVE?

A These curves appear to comply with the Commission's directive regarding variation in customers' rate of return because the cost and revenue curves are parallel. However, the location of the revenue curve relative to the cost curve is internally inconsistent with the results of the cost-of-service study. All these curves show is that a problem (i.e., an inverse relationship between cost and revenue) exists due to PECO's mixing of allocation methodologies, i.e., the use of a 4CP method for determining a rate schedule's revenue requirements and an NCP (Bary curve) method for collecting the demand-related portion of these costs.

Q DIDN'T MR. SUNDERMIER EXPLAIN AWAY THE PROBLEM, I.E., THE INVERSE RELATIONSHIP BETWEEN REVENUE AND COST YOU DESCRIBED ABOVE?

A Mr. Sundermier's explanation beginning on Tr. 1591 is misleading. Each of the curves shown in Section VII stands alone. For example, the 100 kW Rate HT curve (Page 47 of Exhibit WFS-1) represents the average cost and revenue for a Rate HT 100 kW maximum monthly demand customer at various hours of use. If maximum demand varies by month, then new cost and revenue curves, based upon any month's maximum demand could be constructed and evaluated. It

is obvious, however, from the range of demands used in developing the various Rate HT and PD curves, that the mismatch between revenue and costs exist over all levels of monthly maximum demand. I believe the inverse relationship exists because of an improper matching of the 4CP cost allocation study and the application of an NCP Bary curve analysis for rate design.

Q PLEASE EXPLAIN THE DIFFERENCES BETWEEN SCHEDULES 1 THROUGH 4 OF EXHIBIT MPB-4 ( )?

A The difference between the schedules is due to EDH adjustment as follows:

Schedule	EDH Adjustment Made
1	Monthly peak day EDH as per PECO (1984).
2	Monthly peak day EDH based upon 1980 through 1983 average.
3	Monthly peak day EDH based upon 1985 EDH.
4	Monthly peak day EDH = 213.

Q PLEASE DESCRIBE THE RESULTS OF YOUR NCP STUDIES?

A Each of my studies show that the rate of return for Rate HT and PD is above the system average rate of return. The actual rate of return, and revenue subsidy levels at present and proposed rates is summarized in Schedule 5 of Exhibit MPB-4 ( ).

Q DO THESE STUDIES AFFECT THE COST VS. REVENUE RELATIONSHIP FOR RATE SCHEDULES HT AND PD?

A Yes, they do. They would tend to align the cost vs. revenue

relationships shown in Section VII of Exhibit WFS-1 since the NCP earned rate of return at proposed rates is above the system average rate of return. This illustrates that a consistent application of Mr. Bary's General Unified Theory produces explainable cost vs. revenue relationships. Because of PECO's pick and choose mixing of allocation methodologies and the resulting inverse relationship between cost and revenue, the Bary curve should not be used with the 4CP cost-of-service study.

Q WHEN WOULD IT BE PROPER TO USE THE BARY CURVE ANALYSIS?

A It would only be proper to use the Bary curve analysis if the underlying cost of service study which develops rate class revenue requirements is an NCP study. Thus, if the Commission desires to have PECO utilize the Bary curve in the design of commercial/industrial rates, for consistent application, it must require PECO to use an NCP cost-of-service study such as I have developed in Exhibit MPB-4 ( ). The use of any of these NCP studies would require a redistribution of the requested increase in order to reduce the amount of revenue subsidy increase--supplied or received--by the major rate classes.

LOAD CHARACTERISTICS OF PECO AND THE LOAD AND SUPPLY CHARACTERISTICS OF THE PJM INTERCONNECTION SYSTEM

Q HAVE YOU ANALYZED THE LOAD CHARACTERISTICS OF PECO AND BOTH THE LOAD SUPPLY CHARACTERISTICS OF THE PJM INTERCONNECTION SYSTEM?

A Yes, I have. This analysis appears in Appendix B to my testimony.

Q WHAT DOES THIS ANALYSIS SHOW?

A PECO's firm monthly peak demands for the years 1980 through 1984 are shown in Charts 1 through 5. An analysis of the monthly system peaks as a percent of the annual system peak is presented in Appendix B, Schedule 1 and in Charts 6 through 10. Referring to Schedule 1 for the year 1984, Line 6, of Column 6 shows an index value of 100, which means that the annual firm system peak demand for the year 1984 occurred during the month of June. This means that the firm peak demand experienced in April, 1984 was only 67% of the annual firm system peak demand. Lines 13 and 14 of Schedule 1 show the ratio of the annual system peak demand to the minimum monthly peak and the average monthly peak. If the load pattern were essentially flat (i.e., nonseasonal), then these ratios would be close to 1.0. For PECO, however, the ratio of the maximum-to-minimum monthly peak ranges from 1.38 to 1.55. The ratio of the maximum-to-average monthly peak ranges from 1.19 to 1.28. These ranges indicate that PECO's demands are seasonal and that the maximum demands occur during the summer months. This is also when the annual system peak occurs.

Charts 11 through 15 are an analysis of the monthly system peaks as a percent of the annual system cost on the PJM interconnection system. This analysis demonstrates that the PJM total system load pattern is also highly seasonal and that the annual

system peak always occurs during the summer period. The peak demands during the nonsummer months are generally below 85% of the annual system peak. Thus, the PECO and PJM system monthly load patterns are very similar.

Schedules 2 and 3 of Appendix B, along with Charts 16 through 27, present an analysis of PJM interconnected system's capacity, demand, maintenance outages, reserve and capacity margins, and percentage reserve and capacity margins for the years 1979 through 1984.

Appendix B, Schedule 2, Line 1 (and the curve at the top of Charts 16 through 21), shows the PJM system's net plant capability during each month of the year. The net plant capability represents the amount of installed capacity.

Schedule 2, Line 2 (the bottom curve on the charts) shows the monthly peak demand. Line 3, the reserve margin, is the difference between the net plant capability and the system demand. (This is represented by the shaded area between the two curves on Charts 16 through 21.) The reserve margin indicates the extent to which the PJM system's installed plant capability exceeded the system peak demand. During the month of June, 1984, for example, the margin between plant capability and the system peak demand was 10,580 megawatts, which was 30.0% of the system peak demand. This reserve margin provides a safety cushion against scheduled and unscheduled outages of equipment or other contingencies. An examination of the monthly reserve margins, as shown on Schedule 2,

reveals that the amount of unused capacity is less during the peak summer months than during the nonsummer months.

Recognizing that generating units must be removed from service periodically for maintenance, Schedule 3 and Charts 22 through 27 present an analysis of the PJM system's capacity and demand, with an adjustment for scheduled maintenance. The scheduled maintenance outages are shown on Line 2. These effectively reduce the net plant capability of the PJM system. The adjusted capability is shown on Line 3. (On these charts, the adjusted capability is represented by the middle curve.) The difference between this adjusted capability and the system demand is the capacity margin, which is shown on Schedule 3, Line 5 (and the cross-hatched area between the middle and bottom curves on Charts 21 through 25). The capacity margin, as a percent of the system demand, is shown on Line 6.

The capacity margin is a measure of the generating capacity which is available to offset unforeseen contingencies--such as unexpected increases in demand or forced outages. Unlike scheduled maintenance, which the utility can plan in advance, unexpected increases in demand and forced outages are random events over which the utility has limited control.

Generally, the capacity margins, as a percent of the monthly system peak demand, are lowest during the summer period. This is despite the fact that most scheduled maintenance outages occur during the nonsummer months (in order to maximize the amount of

available capacity during the more critical summer months). This indicates that scheduled maintenance causes no apparent capacity problem and that (since sufficient capacity must be installed to meet the summer system peak demands--with an allowance for reserves) additional demand can be served from existing capacity during the nonsummer period.

Q WHAT ARE YOUR CONCLUSIONS REGARDING THIS ANALYSIS?

A This analysis clearly demonstrates that the supply of electric power is more limited during the summer months. Thus, the critical period on the PECO system occurs during the summer months (both with respect to the magnitude of the summer peak demands and the generally lower reserve and capacity margins). The demands during the nonsummer months are not as critical in terms of the amount of capacity to be installed. Because of the predominant summer-peaking characteristic of the PECO and PJM systems and the generally higher reserve and capacity margins on the PJM system during the nonsummer months, it would be appropriate to allocate production and transmission demand-related costs relative to the demands of each customer class imposed during the summer (peak) period.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes, it does.

Qualifications of Melvin P. Bloom

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Melvin Bloom, 1801 N. Front Street, Harrisburg, Pennsylvania.

Q BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A I am a consultant in the field of public utility regulation and am employed by Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q WILL YOU STATE BRIEFLY YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE?

A I am a graduate of the Pennsylvania State University, with the degrees of Bachelor of Science in Electric Engineering, Master of Science in Electrical Engineering, and Doctor of Philosophy in Electrical Engineering--with a minor in Applied Mathematics. From 1963 through 1969 I taught courses in Physics, Electric Engineering at the Pennsylvania State University. From 1970 through 1975, I was Supervisor of the Engineering Section of the Environmental Test Laboratory of AMP, Inc. From 1975 through 1980, while employed as an Engineer in the Bureau of Rates of the Pennsylvania Public Utility Commission, I actively participated and testified in nearly all major electric rate cases regarding the subject of cost of service and rate design. In addition, I authored both the preliminary and final Pennsylvania Generic Electric Rate Structure Investigation Report in Docket No. 76-PRMD-7. From 1970 through 1979, I taught

courses in Mathematics and Electrical Engineering for the Pennsylvania State University and the Lebanon Valley College. In May of 1980, I joined the firm of Drazen-Brubaker & Associates, Inc. My work consists of preparation of financial and economic studies relating to electrical and gas utilities, including determination of cost of service and rate design. I have also testified before the Arizona Corporation Commission, Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, and the New Mexico Public Service Commission.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, In., that was active in that field since 1937. In the last five years our firm has participated in more than 700 rate cases in forty states.

The firm provides consulting services in the field of public utility regulation to many clients, including large industrial customers, schools, hospitals, some utilities and, on occasion, state regulatory agencies. For regulatory proceedings, we regularly prepare studies relating the revenue requirements and rate design. We also prepare depreciation and feasibility studies relating to utility service. In making these studies, it is necessary to analyze utilities' operating and financial records, including property records, depreciation studies, revenues, expenses and taxes, cost studies, load studies, forecasts and siting studies. We also assist in the negotiation of contracts for utility service for large users.

In general, we are engaged in regulatory consulting, rate work, feasibility, economic and cost-of-service studies, design of rates for utility services and contract negotiations.

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Exhibits

of

MELVIN P. BLOOM

On behalf of the

Philadelphia Area Industrial Energy User Group

Allied Corporation, Fibers Division
Boeing Vertol Company
E. I. DuPont, Inc.
The Budd Company
Flavid Air Corporation of North America
Lukens Steel Company
Nabisco Brands, Inc.
SDC (a Burroughs Company)
SmithKline Beckman Corporation
Sun Refining and Marketing Company
3M Company)

and

United States Steel Corporation

January 1986
Project 4035

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

PHILADELPHIA ELECTRIC COMPANY

Results of Cost-of-Service Studies at the Then Present Rates
Four Coincident Peak Method
1974 through 1986

Line	Rate Class	1974 (1)	1975 (2)	1976 (3)	1978 (4)	1979 (5)	1981[a] (6)	1982[b] (7)	1983[c] (8)	1984 (9)	1986[d] (10)
	Rate of Return										
1	High Tension	5.51%	7.92%	7.84%	9.41%	9.86%	7.48%	9.69%	11.08%	11.65%	5.51%[e]
2	Primary	7.50	10.20	9.66	10.08	10.64	8.62	11.12	13.29	14.39	6.21
3	Secondary	10.49	11.40	11.21	13.21	12.72	11.32	13.00	15.36	15.57	8.07
4	Residential	5.12	6.40	6.22	7.30	6.15	7.09	4.78	6.28	5.87	6.39
5	Street Lighting	4.85	6.16	6.25	6.52	5.18	5.15	5.37	7.08	8.72	12.58
6	Total Company	6.00%	7.84%	7.77%	9.04%	8.64%	6.23%	8.17%	9.62%	9.70%	6.39%
	Deviation										
7	High Tension	- 0.49	+ 0.08	+ 0.07	+ 0.37	+ 1.22	+ 1.25	+ 1.52	+ 1.46	+ 1.95	- 0.88[e]
8	Primary	+ 1.50	+ 2.36	+ 1.89	+ 1.04	+ 2.00	+ 2.39	+ 2.95	+ 3.67	+ 4.69	- 0.18
9	Secondary	+ 4.49	+ 3.56	+ 3.44	+ 4.17	+ 4.08	+ 5.09	+ 4.92	+ 5.74	+ 5.87	+ 1.68
10	Residential	- 0.88	- 1.44	- 1.55	- 1.74	- 2.49	- 3.14	- 3.39	- 3.34	- 3.83	0.00
11	Street Lighting	- 1.15	- 1.68	- 1.52	- 2.52	- 3.46	- 1.08	- 2.80	- 2.54	- 0.98	+ 6.19

(a) Year Ended March 31, 1981
(b) Year Ended March 31, 1982
(c) Year Ended October 31, 1983
(d) Year Ending June 30, 1986
(e) Includes AMTRAK and SEPTA

PHILADELPHIA ELECTRIC COMPANY

Summer Peak Day EDH
1980 - 1985

Line	Year	June (1)	July (2)	August (3)	September (4)	Average (5)
1	1980	162	273	260	255	238
2	1981	218	263	198	116	199
3	1982	132	231	179	149	173
4	1983	118	206	199	216	185
5	Average (1980-83)	158	243	209	184	199
6	1984	143	170	131	86	133
7	1985	121	212	234	182	187

PHILADELPHIA ELECTRIC COMPANY

1984 Summer Peak Day EDH
as a Percent of 1980-83 EDH and 1985 EDH

Line	Year	June (1)	July (2)	August (3)	September (4)	Average (5)
1	1984	90.5%	70.0%	62.7%	46.7%	66.8%
2	1980-1983 Average	100.0%	100.0%	100.0%	100.0%	100.0%
3	1984	118.2%	80.2%	56.0%	47.3%	71.1%
4	1985	100.0%	100.0%	100.0%	100.0%	100.0%

PHILADELPHIA ELECTRIC COMPANY

Four Summer Peak Day EDH Average
as a Percent of Hot Period EDH
(1980 - 1985)

Line	Year		EDH as a Percent of Hot Period EDH
1	1980		111.7%
2	1981		93.4
3	1982		81.2
4	1983		86.9
5	Average 1980-1983	=	93.4
6	1984		62.4
7	1985		87.8
8	Hot Period*		100.0%

*Hot Period EDH = 213

PHILADELPHIA ELECTRIC COMPANY

Analysis of Annual Load Factor
and Coincidence Factor
Rates R and GS

Line	Year	Rate R Annual Load Factor (1)	Rate R Index[1] (2)	Rate R Coincidence Factor (3)	Rate R Index[1] (4)	Rate GS Annual Load Factor (5)	Rate GS Index[1] (6)	Rate GS Coincidence Factor (7)	Rate GS Index[1] (8)
1	1980	32.6%	93	36.0%	101	47.2%	95	51.2%	103
2	1981	36.6	105	33.4	94	48.9	99	49.9	101
3	1982	35.8	102	37.8	106	52.6	106	47.5	96
4	1980-1982 Average	35.0	100	35.7	100	49.6	100	49.5	100
5	1984	43.8%	125	29.0%	81	56.1%	113	46.2%	93

1 - Annual load factor or coincidence factor divided by 1980-1982 average value.

PHILADELPHIA ELECTRIC COMPANY

Effect of EDH Adjustment on 1984
Load Factor and Coincidence Factor
Rates R and GS

Line	EDH Adjustment	Rate R				Rate GS			
		Annual Load Factor[1] (1)	Index[2] (2)	Coincidence Factor[1] (3)	Index[2] (4)	Annual Load Factor[1] (5)	Index[2] (6)	Coincidence Factor[1] (7)	Index[2] (8)
1	1980-1983 EDH Average	36.9%	105	34.4%	96	49.2%	99	52.7%	106
2	1985 EDH	33.7	96	33.9	95	49.4	100	52.5	106
3	EDH = 213	33.5	96	34.1	96	48.4	98	53.5	108
4	1980-1982 Average	35.0%	100	35.7%	100	49.6%	100	49.5%	100

1 - 1984 data adjusted for EDH.

2 - Annual load factor or coincidence factor divided by 1980-1982 actual average value (Line 4).

Exhibit MPB-2 ( )
Schedule 5

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
AVERAGE 1980-1983 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
RATE BASE							
ELECTRIC PLANT IN SERVICE	$8,893,834	$2,823,930	$ 661,987	$1,235,547	$ 483,647	$3,251,680	$ 22,508
ACCUMULATED PROVISION FOR DEPREC	1,665,850	468,615	117,472	221,797	98,458	660,950	8,361
NET PLANT IN SERVICE	7,227,984	2,355,315	544,515	1,013,750	385,189	2,590,730	14,147
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	99,969	20,141	34,766	15,584	86,076	3,280
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	853	187	333	115	747	0
LIBERALIZED DEPRECIATION	526,166	167,714	39,318	73,194	28,572	191,434	1,316
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,286,010	524,767	974,027	371,454	2,480,015	15,993
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,962	2,302	4,457	2,052	15,918	950
TOTAL REVENUE	2,290,779	795,519	181,031	332,701	123,832	715,204	24,342
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	515,573	104,794	185,034	82,605	474,479	16,769
DEPRECIATION AND AMORT	264,877	86,897	20,129	36,523	14,057	93,823	871
TAXES OTH THN INCOME TAX	82,178	26,810	6,200	11,654	4,530	28,955	701
INCOME TAXES	34,032	30,555	8,975	16,196	703	-35,085	4,378
PROV FOR DEFERRED INC TAX	41,011	-6,307	2,335	6,433	1,396	33,285	-1,924
INC TX DEF IN PRIOR YR	-13,606	-4,949	-1,090	-1,948	-677	-4,415	-2
INVESTMENT TAX CREDIT	-3,401	-1,084	-254	-473	-185	-1,237	-9
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	647,495	141,089	255,420	102,430	589,805	20,785
NET OPERATING INCOME	444,781	148,024	39,941	77,281	21,403	125,399	3,557
RATE OF RETURN	6.39%	6.48%	7.61%	7.93%	5.76%	5.06%	22.24%
INDEX OF RETURN	100	101	119	124	90	79	348
DEVIATION	.00	.09	1.22	1.55	-.63	-1.33	15.85
REVENUE SUBSIDY	0	4,082	13,048	30,608	-4,719	-67,049	5,150
PROPOSED OPERATING INCOME	$ 884,369	$ 323,891	$ 76,925	$ 141,160	$ 44,437	$ 258,340	$ 5,017
PROPOSED RATE OF RETURN	12.70%	14.17%	14.66%	14.49%	11.96%	10.42%	31.37%
PROPOSED INDEX OF RETURN	100	112	115	114	94	82	247
PROPOSED DEVIATION	.00	1.47	1.96	1.79	-.74	-2.28	18.67
PROPOSED REVENUE SUBSIDY	0	68,189	20,883	35,465	-5,562	-115,022	6,066

Exhibit MPB-3 ( )
Schedule 1
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
AVERAGE 1980-1983 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

RATE BASE	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
ELECTRIC PLANT IN SERVICE	$ 47,809	$ 66,433	$ 5,395	$ 133,457	$ 14,969	$ 64,437	$ 82,034
ACCUMULATED PROVISION FOR DEPREC	15,586	23,077	1,863	21,524	2,518	11,352	14,278
NET PLANT IN SERVICE	32,223	43,356	3,532	111,933	12,451	53,086	67,756
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,224	1,209	188	3,608	472	2,100	3,537
DEDUCTIONS							
ACCELERATED AMORTIZATION	0	0	0	41	4	18	24
LIBERALIZED DEPRECIATION	2,839	3,946	319	7,935	888	3,827	4,862
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	30,355	40,266	3,372	107,564	12,030	51,302	66,377
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	33	20	28	295	33	205	2,708
TOTAL REVENUE	13,464	17,742	2,328	29,928	4,836	18,449	31,404
EXPENSES							
OPERATION AND MAINT EXP	6,592	6,822	1,012	15,090	1,902	10,865	19,369
DEPRECIATION AND AMORT	1,080	2,302	171	4,137	458	1,927	2,500
TAXES OTH THN INCOME TAX	483	635	74	521	59	611	945
INCOME TAXES	1,760	2,050	437	-757	544	1,221	3,055
PROV FOR DEFERRED INC TAX	175	660	-9	3,167	348	-30	-518
INC TX DEF IN PRIOR YR	-6	-7	-1	-240	-26	-106	-141
INVESTMENT TAX CREDIT	-18	-26	-2	-51	-6	-25	-31
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,067	12,436	1,683	21,867	3,279	14,464	25,179
NET OPERATING INCOME	3,397	5,306	645	8,061	1,557	3,985	6,225
RATE OF RETURN	11.19%	13.18%	19.12%	7.49%	12.94%	7.77%	9.38%
INDEX OF RETURN	175	206	299	117	203	122	147
DEVIATION	4.80	6.79	12.74	1.11	6.55	1.38	2.99
REVENUE SUBSIDY	2,962	5,554	872	2,418	1,602	1,438	4,033
PROPOSED OPERATING INCOME	$ 3,760	$ 5,531	$ 698	$ 8,062	$ 1,557	$ 6,448	$ 8,543
PROPOSED RATE OF RETURN	12.39%	13.74%	20.70%	7.50%	12.94%	12.57%	12.87%
PROPOSED INDEX OF RETURN	98	108	163	59	102	99	101
PROPOSED DEVIATION	-.31	1.04	6.00	-5.20	.24	-.13	.17
PROPOSED REVENUE SUBSIDY	-194	847	548	-11,372	59	-137	230

Exhibit MPB-3 ( )
Schedule 1
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
RATE BASE							
ELECTRIC PLANT IN SERVICE	$8,893,834	$2,871,155	$ 672,201	$1,226,341	$ 475,210	$3,207,112	$ 22,435
ACCUMULATED PROVISION FOR DEPREC	1,665,850	475,777	118,983	220,181	97,058	654,595	8,334
NET PLANT IN SERVICE	7,227,984	2,395,378	553,218	1,006,160	378,151	2,552,517	14,101
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	100,481	20,252	34,666	15,492	85,594	3,279
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	868	190	331	112	732	0
LIBERALIZED DEPRECIATION	526,166	170,534	39,928	72,644	28,068	188,773	1,311
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,323,751	532,969	966,894	364,832	2,493,984	15,952
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	10,059	2,323	4,440	2,036	15,823	950
TOTAL REVENUE	2,290,779	795,616	181,052	332,684	123,816	715,109	24,342
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	518,688	105,468	184,426	82,048	471,542	16,764
DEPRECIATION AND AMORT	264,877	88,379	20,451	36,242	13,796	92,410	870
TAXES OTH THN INCOME TAX	82,178	26,993	6,239	11,619	4,497	28,783	701
INCOME TAXES	34,032	26,199	8,030	17,026	1,471	-30,941	4,384
PROV FOR DEFERRED INC TAX	41,011	-5,145	2,587	8,215	1,193	32,172	-1,925
INC TX DEF IN PRIOR YR	-13,606	-5,037	-1,109	-1,932	-662	-4,329	-2
INVESTMENT TAX CREDIT	-3,401	-1,102	-258	-470	-181	-1,220	-8
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	648,975	141,409	255,126	102,162	588,418	20,782
NET OPERATING INCOME	444,781	146,641	39,643	77,558	21,653	126,691	3,559
RATE OF RETURN	6.39%	6.31%	7.44%	8.02%	5.94%	5.18%	22.31%
INDEX OF RETURN	100	99	116	126	93	81	349
DEVIATION	.00	-.08	1.05	1.63	-.45	-1.20	15.93
REVENUE SUBSIDY	0	-3,624	11,378	32,095	-3,351	-59,750	5,161
PROPOSED OPERATING INCOME	$ 884,369	$ 322,508	$ 76,628	$ 141,436	$ 44,687	$ 259,631	$ 5,020
PROPOSED RATE OF RETURN	12.70%	13.88%	14.38%	14.63%	12.25%	10.62%	31.47%
PROPOSED INDEX OF RETURN	100	109	113	115	96	84	248
PROPOSED DEVIATION	.00	1.18	1.68	1.93	-.45	-2.08	18.77
PROPOSED REVENUE SUBSIDY	0	55,643	18,162	37,866	-3,344	-103,102	6,082

Exhibit MPB-3 ( )
Schedule 2
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
RATE BASE							
ELECTRIC PLANT IN SERVICE	$ 47,737	$ 66,424	$ 5,392	$ 135,753	$ 15,216	$ 65,436	$ 83,364
ACCUMULATED PROVISION FOR DEPREC	15,580	23,073	1,862	21,873	2,555	11,502	14,477
NET PLANT IN SERVICE	32,217	43,350	3,530	113,880	12,661	53,934	68,887
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,223	1,208	168	3,633	474	2,111	3,551
DEDUCTIONS							
ACCELERATED AMORTIZATION	0	0	0	42	5	18	25
LIBERALIZED DEPRECIATION	2,839	3,945	319	8,072	903	3,886	4,942
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	30,349	40,261	3,370	109,398	12,228	52,102	67,443
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	33	20	28	300	33	207	2,711
TOTAL REVENUE	13,464	17,742	2,328	29,933	4,836	18,451	31,407
EXPENSES							
OPERATION AND MAINT EXP	6,591	6,821	1,012	15,242	1,918	10,931	19,455
DEPRECIATION AND AMORT	1,080	2,302	171	4,209	466	1,958	2,542
TAXES OTH THN INCOME TAX	483	635	74	530	60	614	950
INCOME TAXES	1,761	2,051	437	-969	521	1,129	2,933
PROV FOR DEFERRED INC TAX	175	660	-9	3,223	354	-5	-485
INC TX DEF IN PRIOR YR	-6	-7	-1	-244	-26	-107	-143
INVESTMENT TAX CREDIT	-18	-26	-2	-52	-6	-25	-32
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,066	12,436	1,683	21,939	3,287	14,495	25,220
NET OPERATING INCOME	3,398	5,306	645	7,994	1,550	3,956	6,187
RATE OF RETURN	11.20%	13.18%	19.14%	7.31%	12.67%	7.59%	9.17%
INDEX OF RETURN	175	206	300	114	198	119	144
DEVIATION	4.81	6.79	12.75	.92	6.29	1.21	2.79
REVENUE SUBSIDY	2,964	5,555	873	2,044	1,561	1,275	3,818
PROPOSED OPERATING INCOME	$ 3,760	$ 5,531	$ 698	$ 7,995	$ 1,550	$ 6,419	$ 8,505
PROPOSED RATE OF RETURN	12.39%	13.74%	20.72%	7.31%	12.67%	12.32%	12.61%
PROPOSED INDEX OF RETURN	96	108	163	58	100	97	99
PROPOSED DEVIATION	-.31	1.04	8.02	-5.39	-.03	-.38	-.09
PROPOSED REVENUE SUBSIDY	-192	849	549	-11,982	-7	-403	-122

Exhibit MPB-3 ( )
Schedule 2
Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
213 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
RATE BASE							
ELECTRIC PLANT IN SERVICE	$8,893,834	$2,778,251	$ 651,762	$1,245,027	$ 496,216	$3,291,099	$ 21,739
ACCUMULATED PROVISION FOR DEPREC	1,665,850	461,398	115,799	223,343	100,243	667,578	8,065
NET PLANT IN SERVICE	7,227,984	2,316,854	535,963	1,021,684	395,973	2,623,521	13,675
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	99,473	20,030	34,869	15,720	86,504	3,271
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	839	184	336	119	759	0
LIBERALIZED DEPRECIATION	526,166	164,986	38,708	73,760	29,323	193,788	1,270
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,249,798	516,719	981,493	381,622	2,510,856	15,563
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,870	2,282	4,476	2,079	15,994	950
TOTAL REVENUE	2,290,779	795,427	181,011	332,720	123,859	715,280	24,342
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	512,558	104,119	185,659	83,434	477,081	16,718
DEPRECIATION AND AMORT	264,877	85,471	19,812	36,818	14,456	95,040	853
TAXES OTH THN INCOME TAX	82,178	26,634	6,160	11,691	4,578	29,107	698
INCOME TAXES	34,032	34,746	9,909	15,330	-467	-38,668	4,434
PROV FOR DEFERRED INC TAX	41,011	-7,420	2,086	8,662	1,711	34,230	-1,936
INC TX DEF IN PRIOR YR	-13,606	-4,866	-1,071	-1,965	-701	-4,483	-2
INVESTMENT TAX CREDIT	-3,401	-1,066	-250	-477	-190	-1,253	-8
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	646,057	140,766	255,719	102,821	591,054	20,757
NET OPERATING INCOME	444,781	149,370	40,245	77,001	21,039	124,225	3,585
RATE OF RETURN	6.39%	6.64%	7.79%	7.85%	5.51%	4.95%	23.04%
INDEX OF RETURN	100	104	122	123	86	77	361
DEVIATION	.00	.25	1.40	1.46	-.87	-1.44	16.65
REVENUE SUBSIDY	0	11,516	14,708	29,069	-6,778	-73,435	5,263
PROPOSED OPERATING INCOME	$ 884,369	$ 325,238	$ 77,229	$ 140,879	$ 44,073	$ 257,166	$ 5,046
PROPOSED RATE OF RETURN	12.70%	14.46%	14.95%	14.35%	11.55%	10.24%	32.42%
PROPOSED INDEX OF RETURN	100	114	118	113	91	81	255
PROPOSED DEVIATION	.00	1.76	2.25	1.65	-1.15	-2.46	19.72
PROPOSED REVENUE SUBSIDY	0	80,266	23,575	32,968	-8,925	-125,363	6,235

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
213 EDH STUDY
FOUR PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

RATE BASE	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
ELECTRIC PLANT IN SERVICE	$ 47,777	$ 66,415	$ 5,390	$ 131,248	$ 14,727	$ 63,462	$ 80,721
ACCUMULATED PROVISION FOR DEPREC	15,574	23,071	1,861	21,177	2,479	11,196	14,066
NET PLANT IN SERVICE	32,202	43,344	3,529	110,071	12,247	52,266	66,654
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,223	1,208	108	3,584	469	2,090	3,523
DEDUCTIONS							
ACCELERATED AMORTIZATION	0	0	0	41	4	18	24
LIBERALIZED DEPRECIATION	2,838	3,945	319	7,803	874	3,768	4,784
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	30,336	40,255	3,369	105,811	11,839	50,530	65,341
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	33	20	28	291	32	203	2,705
TOTAL REVENUE	13,464	17,742	2,328	29,924	4,835	18,447	31,401
EXPENSES							
OPERATION AND MAINT EXP	6,590	6,820	1,011	14,945	1,886	10,800	19,285
DEPRECIATION AND AMORT	1,080	2,302	171	4,068	451	1,897	2,459
TAXES OTH THN INCOME TAX	483	635	74	513	58	607	940
INCOME TAXES	1,762	2,052	438	-554	566	1,311	3,174
PROV FOR DEFERRED INC TAX	175	660	-9	3,113	342	-53	-550
INC TX DEF IN PRIOR YR	-6	-7	-1	-236	-26	-104	-138
INVESTMENT TAX CREDIT	-18	-25	-2	-50	-6	-24	-31
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,066	12,436	1,683	21,798	3,272	14,433	25,139
NET OPERATING INCOME	3,398	5,307	645	8,126	1,564	4,014	6,263
RATE OF RETURN	11.20%	13.18%	19.15%	7.68%	13.21%	7.94%	9.59%
INDEX OF RETURN	175	206	300	120	207	124	150
DEVIATION	4.82	6.80	12.76	1.29	6.82	1.56	3.20
REVENUE SUBSIDY	2,967	5,557	873	2,778	1,641	1,597	4,244
PROPOSED OPERATING INCOME	$ 3,761	$ 5,532	$ 698	$ 8,127	$ 1,564	$ 6,477	$ 8,581
PROPOSED RATE OF RETURN	12.40%	13.74%	20.72%	7.68%	13.21%	12.82%	13.13%
PROPOSED INDEX OF RETURN	98	108	163	60	104	101	103
PROPOSED DEVIATION	-.30	1.04	8.02	-5.02	-.51	-.12	-.43
PROPOSED REVENUE SUBSIDY	-187	851	549	-10,788	123	120	574

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PHILADELPHIA ELECTRIC COMPANY

Rate of Return Summary of
4CP Cost of Service
for Various Weather Adjustments
Twelve Months Ending June 30, 1986

Line	Rate Schedule	Present			Proposed		
		1980-1983 EDH Average (1)	1985 EDH (2)	EDH=213 (3)	1980-1983 EDH Average (4)	1985 EDH (5)	EDH=213 (6)
1	HT	6.48%	6.31%	6.64%	14.17%	13.88%	14.46%
2	PD	7.61	7.44	7.79	14.66	14.38	14.95
3	GS	7.93	8.02	7.85	14.49	14.63	14.35
4	RH	5.76	5.94	5.51	11.96	12.25	11.55
5	R	5.06	5.18	4.95	10.42	10.62	10.24
6	OP	22.24	22.31	23.04	31.37	31.47	32.42
7	SLP	11.19	11.20	11.20	12.39	12.39	12.40
8	SLS	13.18	13.18	13.18	13.74	13.74	13.74
9	Other SL	19.12	19.14	19.15	20.70	20.72	20.72
10	Other Utilities	7.49	7.31	7.68	7.50	7.31	7.68
11	Interdepartmental	12.94	12.67	13.21	12.94	12.67	13.21
12	SEPTA	7.77	7.59	7.94	12.57	12.32	12.82
13	AMTRAK	9.38	9.17	9.59	12.87	12.61	13.13
14	Total Company	6.39%	6.39%	6.39%	12.70%	12.70%	12.70%

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PHILADELPHIA ELECTRIC COMPANY

Revenue Subsidy Summary of
4CP Cost of Service
for Various Weather Adjustments
Twelve Months Ending June 30, 1986

Line	Rate Schedule	Present 1980-1983 EDH Average (000) (1)	Present 1985 EDH (000) (2)	Present EDH=213 (000) (3)	Proposed 1980-1983 EDH Average (000) (4)	Proposed 1985 EDH (000) (5)	Proposed EDH=213 (000) (6)
1	HT	$ 4,082	$(3,624)	$11,516	$ 68,189	$ 55,643	$ 80,266
2	PD	13,048	11,378	14,708	20,883	18,162	23,575
3	GS	30,608	32,095	29,069	35,465	37,866	32,968
4	RH	(4,719)	(3,351)	(6,778)	(5,562)	(3,344)	(8,925)
5	R	(67,049)	(59,750)	(73,435)	(115,022)	(103,102)	(125,363)
6	OP	5,150	5,161	5,263	6,066	6,082	6,235
7	SLP	2,962	2,964	2,967	(194)	(192)	(187)
8	SLS	5,554	5,555	5,557	847	849	851
9	Other SL	872	873	873	548	549	549
10	Other Utilities	2,418	2,044	2,778	(11,372)	(11,982)	(10,788)
11	Interdepartmental	1,602	1,561	1,641	59	(7)	123
12	SEPTA	1,438	1,275	1,597	(137)	(403)	120
13	AMTRAK	4,033	3,818	4,244	230	(122)	574
14	Total Company	$ -0-	$ -0-	$ -0-	$ -0-	$ -0-	$ -0-

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
COMPANY STUDY
NON-COINCIDENT PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
RATE BASE							
ELECTRIC PLANT IN SERVICE	$8,893,834	$2,772,037	$ 714,737	$1,028,339	$ 819,919	$2,914,476	$ 125,465
ACCUMULATED PROVISION FOR DEPREC	1,665,850	462,244	126,515	189,360	151,724	605,192	24,227
NET PLANT IN SERVICE	7,227,984	2,309,793	588,223	838,979	668,196	2,309,284	101,239
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	99,411	20,715	32,520	19,234	82,418	4,397
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	835	203	268	220	644	33
LIBERALIZED DEPRECIATION	526,166	164,615	42,469	60,820	48,653	171,297	7,464
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,243,015	565,865	809,458	637,889	2,215,230	98,021
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,844	2,403	4,038	2,725	15,261	1,160
TOTAL REVENUE	2,290,779	795,401	181,132	332,282	124,505	714,547	24,552
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	512,185	108,284	171,375	104,803	452,254	23,562
DEPRECIATION AND AMORT	264,877	85,224	21,756	30,047	24,537	83,383	4,096
TAXES OTH THN INCOME TAX	82,178	26,611	6,404	10,854	5,829	27,652	1,099
INCOME TAXES	34,032	35,440	4,185	35,226	-30,126	-4,371	-5,099
PROV FOR DEFERRED INC TAX	41,011	-7,633	3,597	3,369	9,580	25,159	600
INC TX DEF IN PRIOR YR	-13,606	-4,843	-1,181	-1,569	-1,286	-3,819	-192
INVESTMENT TAX CREDIT	-3,401	-1,064	-275	-393	-314	-1,107	-48
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	645,919	142,770	248,909	113,023	579,149	24,017
NET OPERATING INCOME	444,781	149,481	38,361	83,372	11,482	135,398	534
RATE OF RETURN	6.39%	6.66%	6.78%	10.30%	1.80%	6.11%	.54%
INDEX OF RETURN	100	104	106	161	28	96	9
DEVIATION	.00	.28	.39	3.91	-4.59	-.28	-5.04
REVENUE SUBSIDY	0	12,622	4,506	64,334	-59,442	-12,383	-11,633
PROPOSED OPERATING INCOME	$ 884,369	$ 325,349	$ 75,345	$ 147,251	$ 34,516	$ 268,338	$ 1,995
PROPOSED RATE OF RETURN	12.70%	14.50%	13.32%	18.19%	5.41%	12.11%	2.03%
PROPOSED INDEX OF RETURN	100	114	105	143	43	95	16
PROPOSED DEVIATION	.00	1.80	.62	5.49	-7.29	-.59	-10.67
PROPOSED REVENUE SUBSIDY	0	82,242	7,070	90,295	-94,451	-26,400	-21,236

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
COMPANY STUDY
NON-COINCIDENT PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
RATE BASE							
ELECTRIC PLANT IN SERVICE	$ 75,381	$ 84,219	$ 10,162	$ 100,509	$ 14,974	$ 86,448	$ 147,167
ACCUMULATED PROVISION FOR DEPREC	19,892	25,855	2,608	16,506	2,532	14,793	24,403
NET PLANT IN SERVICE	55,488	58,363	7,555	84,002	12,443	71,656	122,764
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,523	1,402	239	3,251	472	2,339	4,233
DEDUCTIONS							
ACCELERATED AMORTIZATION	9	6	2	31	4	25	45
LIBERALIZED DEPRECIATION	4,436	5,003	604	5,968	888	5,141	8,752
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	52,262	54,398	7,160	81,255	12,022	68,789	118,169
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	89	56	37	228	33	249	2,840
TOTAL REVENUE	13,520	17,778	2,337	29,861	4,836	18,493	31,536
EXPENSES							
OPERATION AND MAINT EXP	8,412	7,996	1,326	12,918	1,902	12,318	23,572
DEPRECIATION AND AMORT	1,942	2,858	320	3,103	458	2,615	4,538
TAXES OTH THN INCOME TAX	589	704	93	394	59	696	1,195
INCOME TAXES	-773	416	-1	2,280	544	-802	-2,888
PROV FOR DEFERRED INC TAX	849	1,094	108	2,357	348	508	1,076
INC TX DEF IN PRIOR YR	-56	-40	-9	-179	-26	-146	-260
INVESTMENT TAX CREDIT	-29	-32	-4	-39	-6	-33	-57
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,934	12,996	1,833	20,835	3,280	15,156	27,176
NET OPERATING INCOME	2,586	4,782	505	9,026	1,556	3,337	4,360
RATE OF RETURN	4.95%	8.79%	7.05%	11.11%	12.94%	4.85%	3.69%
INDEX OF RETURN	77	138	110	174	203	76	58
DEVIATION	-1.44	2.40	.66	4.72	6.56	-1.54	-2.70
REVENUE SUBSIDY	-1,528	2,657	96	7,792	1,601	-2,147	-6,475
PROPOSED OPERATING INCOME	$ 2,948	$ 5,007	$ 558	$ 9,027	$ 1,556	$ 5,800	$ 6,679
PROPOSED RATE OF RETURN	5.64%	9.21%	7.79%	11.11%	12.94%	8.43%	5.65%
PROPOSED INDEX OF RETURN	44	72	61	87	102	66	45
PROPOSED DEVIATION	-7.06	-3.49	-4.91	-1.59	.24	-4.27	-7.05
PROPOSED REVENUE SUBSIDY	-7,494	-3,862	-714	-2,625	60	-5,965	-16,919

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
AVERAGE 1980-1983 EDH STUDY
NON-COINCIDENT PEAK METHOD
THELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
RATE BASE							
ELECTRIC PLANT IN SERVICE	$8,893,834	$2,590,049	$ 668,631	$1,079,319	$ 766,989	$3,168,171	$ 128,619
ACCUMULATED PROVISION FOR DEPREC	1,665,850	432,572	118,496	197,721	142,123	648,080	24,714
NET PLANT IN SERVICE	7,227,984	2,157,477	550,136	881,598	624,867	2,520,091	103,905
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	97,435	20,214	33,073	18,657	85,174	4,431
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	778	189	283	205	720	34
LIBERALIZED DEPRECIATION	526,166	153,747	39,715	63,864	45,493	186,447	7,652
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,099,679	530,062	849,561	597,194	2,413,486	100,532
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,484	2,315	4,138	2,630	15,748	1,166
TOTAL REVENUE	2,290,779	795,041	181,044	332,382	124,410	715,034	24,558
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	500,169	105,239	174,738	101,303	469,000	23,770
DEPRECIATION AND AMORT	264,877	79,571	20,337	31,630	22,932	91,207	4,195
TAXES OTH THN INCOME TAX	82,178	25,908	6,226	11,051	5,624	28,633	1,111
INCOME TAXES	34,032	52,071	8,360	30,571	-25,381	-27,413	-5,389
PROV FOR DEFERRED INC TAX	41,011	-12,040	2,498	4,603	8,343	31,237	677
INC TX DEF IN PRIOR YR	-13,606	-4,518	-1,102	-1,660	-1,199	-4,261	-198
INVESTMENT TAX CREDIT	-3,401	-994	-257	-413	-294	-1,205	-49
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	640,166	141,301	250,521	111,328	587,199	24,116
NET OPERATING INCOME	444,781	154,875	39,743	81,862	13,083	127,835	442
RATE OF RETURN	6.39%	7.38%	7.50%	9.64%	2.19%	5.30%	.44%
INDEX OF RETURN	100	115	117	151	34	83	7
DEVIATION	.00	.99	1.11	3.25	-4.20	-1.09	-5.95
REVENUE SUBSIDY	0	42,177	11,958	56,062	-50,910	-53,469	-12,147
PROPOSED OPERATING INCOME	$ 884,369	$ 330,743	$ 76,727	$ 145,740	$ 36,117	$ 260,775	$ 1,902
PROPOSED RATE OF RETURN	12.70%	15.75%	14.48%	17.15%	6.05%	10.80%	1.89%
PROPOSED INDEX OF RETURN	100	124	114	135	48	85	15
PROPOSED DEVIATION	.00	3.05	1.78	4.45	-6.65	-1.90	-10.81
PROPOSED REVENUE SUBSIDY	0	130,178	19,114	76,880	-80,701	-92,911	-22,072

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
AVERAGE 1980-1983 EDH STUDY
NON-COINCIDENT PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
RATE BASE							
ELECTRIC PLANT IN SERVICE	$ 73,261	$ 82,863	$ 9,799	$ 93,788	$ 13,984	$ 80,981	$ 137,379
ACCUMULATED PROVISION FOR DEPREC	19,508	25,609	2,542	15,410	2,366	13,901	22,807
NET PLANT IN SERVICE	53,753	57,253	7,257	78,377	11,618	67,080	114,572
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,500	1,387	236	3,178	461	2,280	4,128
DEDUCTIONS							
ACCELERATED AMORTIZATION	8	5	1	29	4	23	42
LIBERALIZED DEPRECIATION	4,359	4,927	582	5,566	829	4,815	8,168
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	50,633	53,355	6,881	75,960	11,246	64,483	110,462
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	85	54	37	214	31	238	2,821
TOTAL REVENUE	13,516	17,776	2,337	29,847	4,834	18,482	31,517
EXPENSES							
OPERATION AND MAINT EXP	8,272	7,906	1,302	12,474	1,837	11,957	22,940
DEPRECIATION AND AMORT	1,678	2,817	309	2,895	427	2,445	4,234
TAXES OTH THN INCOME TAX	581	699	91	368	55	674	1,157
INCOME TAXES	-583	538	32	2,894	635	-302	-2,000
PROV FOR DEFERRED INC TAX	799	1,063	99	2,194	324	376	839
INC TX DEF IN PRIOR YR	-53	-38	-9	-167	-24	-136	-243
INVESTMENT TAX CREDIT	-28	-32	-4	-36	-5	-31	-53
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,866	12,952	1,821	20,622	3,248	14,983	26,874
NET OPERATING INCOME	2,650	4,824	515	9,225	1,586	3,499	4,643
RATE OF RETURN	5.23%	9.04%	7.49%	12.14%	14.10%	5.43%	4.20%
INDEX OF RETURN	62	142	117	190	221	85	66
DEVIATION	-1.15	2.65	1.10	5.76	7.71	-.96	-2.18
REVENUE SUBSIDY	-1,187	2,876	154	8,883	1,762	-1,259	-4,901
PROPOSED OPERATING INCOME	$ 3,012	$ 5,048	$ 569	$ 9,226	$ 1,586	$ 5,962	$ 6,961
PROPOSED RATE OF RETURN	5.95%	9.46%	8.26%	12.15%	14.10%	9.25%	6.30%
PROPOSED INDEX OF RETURN	47	75	65	96	111	73	50
PROPOSED DEVIATION	-6.75	-3.24	-4.44	-.55	1.40	-3.45	-6.40
PROPOSED REVENUE SUBSIDY	-6,943	-3,510	-620	-854	320	-4,525	-14,357

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
NON-COINCIDENT PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
RATE BASE							
ELECTRIC PLANT IN SERVICE	$8,893,634	$2,577,115	$ 665,361	$1,071,022	$ 763,247	$3,198,937	$ 128,001
ACCUMULATED PROVISION FOR DEPREC	1,665,850	430,463	117,929	196,245	141,447	653,335	24,602
NET PLANT IN SERVICE	7,227,984	2,146,652	547,432	874,777	621,800	2,545,602	103,399
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	97,295	20,178	32,983	18,617	85,508	4,424
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	774	166	281	204	729	34
LIBERALIZED DEPRECIATION	526,166	152,975	39,520	63,369	45,269	188,285	7,616
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,089,492	527,520	843,152	594,313	2,437,474	100,057
REVENUE							
SALES	2,251,817	785,557	178,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,459	2,309	4,123	2,624	15,806	1,165
TOTAL REVENUE	2,290,779	795,016	181,038	332,367	124,404	715,092	24,557
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	499,315	105,023	174,190	101,056	471,031	23,729
DEPRECIATION AND AMORT	264,877	79,169	20,237	31,377	22,818	92,154	4,176
TAXES OTH THN INCOME TAX	82,178	25,858	6,213	11,019	5,610	28,752	1,109
INCOME TAXES	34,032	53,253	8,657	31,318	-25,045	-30,202	-5,334
PROV FOR DEFERRED INC TAX	41,011	-12,354	2,420	4,407	8,255	31,972	663
INC TX DEF IN PRIOR YR	-13,606	-4,495	-1,096	-1,646	-1,193	-4,314	-197
INVESTMENT TAX CREDIT	-3,401	-989	-255	-410	-293	-1,217	-49
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	639,757	141,197	250,255	111,208	588,176	24,097
NET OPERATING INCOME	444,781	155,259	39,841	82,112	13,196	126,916	460
RATE OF RETURN	6.39%	7.43%	7.55%	9.74%	2.22%	5.21%	.46%
INDEX OF RETURN	100	116	118	152	35	82	7
DEVIATION	.00	1.04	1.17	3.35	-4.17	-1.18	-5.93
REVENUE SUBSIDY	0	44,278	12,467	57,401	-50,307	-58,449	-12,047
PROPOSED OPERATING INCOME	$ 884,369	$ 331,126	$ 76,825	$ 145,990	$ 36,230	$ 259,856	$ 1,921
PROPOSED RATE OF RETURN	12.70%	15.85%	14.56%	17.31%	6.10%	10.66%	1.92%
PROPOSED INDEX OF RETURN	100	125	115	136	48	84	15
PROPOSED DEVIATION	.00	3.15	1.86	4.61	-6.60	-2.04	-10.78
PROPOSED REVENUE SUBSIDY	0	133,585	19,969	79,041	-79,728	-100,966	-21,911

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
1985 EDH STUDY
NON-COINCIDENT PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

RATE BASE	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
ELECTRIC PLANT IN SERVICE	$ 73,111	$ 82,767	$ 9,773	$ 93,310	$ 13,914	$ 80,592	$ 136,684
ACCUMULATED PROVISION FOR DEPREC	19,481	25,592	2,537	15,332	2,355	13,838	22,694
NET PLANT IN SERVICE	53,630	57,175	7,236	77,978	11,560	66,755	113,990
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,498	1,386	235	3,172	460	2,276	4,121
DEDUCTIONS							
ACCELERATED AMORTIZATION	8	5	1	29	4	23	42
LIBERALIZED DEPRECIATION	4,350	4,921	581	5,538	825	4,791	8,126
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	50,517	53,282	6,861	75,584	11,191	64,177	109,914
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	85	54	37	213	31	238	2,820
TOTAL REVENUE	13,516	17,776	2,337	29,846	4,834	18,482	31,516
EXPENSES							
OPERATION AND MAINT EXP	8,262	7,900	1,301	12,443	1,832	11,931	22,895
DEPRECIATION AND AMORT	1,873	2,814	308	2,880	425	2,433	4,212
TAXES OTH THN INCOME TAX	561	698	91	366	55	673	1,155
INCOME TAXES	-570	546	34	2,938	641	-266	-1,937
PROV FOR DEFERRED INC TAX	796	1,060	98	2,182	322	367	822
INC TX DEF IN PRIOR YR	-52	-38	-9	-166	-24	-135	-241
INVESTMENT TAX CREDIT	-28	-32	-4	-36	-5	-31	-53
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,861	12,949	1,820	20,607	3,246	14,971	26,853
NET OPERATING INCOME	2,654	4,826	516	9,239	1,588	3,511	4,663
RATE OF RETURN	5.25%	9.06%	7.53%	12.22%	14.19%	5.47%	4.24%
INDEX OF RETURN	82	142	118	191	222	86	66
DEVIATION	-1.13	2.67	1.14	5.84	7.80	-.92	-2.14
REVENUE SUBSIDY	-1,162	2,891	159	8,961	1,773	-1,196	-4,789
PROPOSED OPERATING INCOME	$ 3,017	$ 5,051	$ 569	$ 9,240	$ 1,588	$ 5,973	$ 6,981
PROPOSED RATE OF RETURN	5.97%	9.48%	8.30%	12.23%	14.19%	9.31%	6.35%
PROPOSED INDEX OF RETURN	47	75	65	96	112	73	50
PROPOSED DEVIATION	-6.73	-3.22	-4.40	-.47	1.49	-3.39	-6.35
PROPOSED REVENUE SUBSIDY	-6,905	-3,485	-613	-729	338	-4,423	-14,175

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
213 EDH STUDY
NON-COINCIDENT PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	TOTAL	HIGH TENSION	PRIMARY	SECONDARY	RATE RH	RATE R	RATE OP
RATE BASE							
ELECTRIC PLANT IN SERVICE	18,893,834	$2,570,159	$ 663,602	$1,086,420	$ 761,237	$3,203,440	$ 119,849
ACCUMULATED PROVISION FOR DEPREC	1,665,850	429,329	117,624	198,901	141,085	654,069	23,184
NET PLANT IN SERVICE	7,227,984	2,140,830	545,978	887,520	620,152	2,549,371	96,665
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	272,153	97,219	20,159	33,150	18,595	85,557	4,336
DEDUCTIONS							
ACCELERATED AMORTIZATION	2,323	772	188	286	203	731	31
LIBERALIZED DEPRECIATION	526,166	152,560	39,415	64,288	45,149	188,554	7,129
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	6,963,532	2,084,013	526,154	855,132	592,766	2,441,020	93,727
REVENUE							
SALES	2,251,817	785,557	176,729	328,244	121,780	699,286	23,392
OTHER	38,962	9,445	2,306	4,152	2,620	15,815	1,150
TOTAL REVENUE	2,290,779	795,002	181,035	332,396	124,400	715,101	24,542
EXPENSES							
OPERATION AND MAINT EXP	1,440,907	498,856	104,906	175,207	100,923	471,328	23,191
DEPRECIATION AND AMORT	264,877	78,953	20,183	31,850	22,757	92,294	3,926
TAXES OTH THN INCOME TAX	82,178	25,831	6,206	11,079	5,602	28,769	1,077
INCOME TAXES	34,032	53,888	8,816	29,924	-24,864	-30,614	-4,597
PROV FOR DEFERRED INC TAX	41,011	-12,522	2,378	4,774	8,208	32,081	469
INC TX DEF IN PRIOR YR	-13,606	-4,482	-1,093	-1,672	-1,190	-4,322	-183
INVESTMENT TAX CREDIT	-3,401	-986	-255	-416	-292	-1,219	-46
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	1,845,998	639,537	141,141	250,745	111,144	588,318	23,837
NET OPERATING INCOME	444,781	155,465	39,894	81,651	13,257	126,783	705
RATE OF RETURN	6.39%	7.46%	7.58%	9.55%	2.24%	5.19%	.75%
INDEX OF RETURN	100	117	119	149	35	81	12
DEVIATION	.00	1.07	1.19	3.16	-4.15	-1.19	-5.64
REVENUE SUBSIDY	0	45,408	12,771	54,910	-49,983	-59,180	-10,729
PROPOSED OPERATING INCOME	$ 884,369	$ 331,332	$ 76,878	$ 145,529	$ 36,291	$ 259,723	$ 2,165
PROPOSED RATE OF RETURN	12.70%	15.90%	14.61%	17.02%	6.12%	10.64%	2.31%
PROPOSED INDEX OF RETURN	100	125	115	134	48	84	18
PROPOSED DEVIATION	.00	3.20	1.91	4.32	-6.58	-2.06	-10.39
PROPOSED REVENUE SUBSIDY	0	135,418	20,428	75,014	-79,205	-102,152	-19,782

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PHILADELPHIA ELECTRIC COMPANY
COST OF SERVICE
213 EDH STUDY
NON-COINCIDENT PEAK METHOD
TWELVE MONTHS ENDING JUNE 30, 1986
(DOLLAR AMOUNTS IN THOUSANDS)

	RATE SLP	RATE SLS	OTH SL	OTHER UTILITIES	INTER DEPARTMT	SEPTA	AMTRAK
RATE BASE							
ELECTRIC PLANT IN SERVICE	$ 73,031	$ 82,715	$ 9,760	$ 93,053	$ 13,876	$ 80,383	$ 136,310
ACCUMULATED PROVISION FOR DEPREC	19,466	25,583	2,535	15,290	2,348	13,804	22,633
NET PLANT IN SERVICE	53,564	57,133	7,225	77,763	11,527	66,580	113,676
RATE BASE ADJUSTMENTS							
ADDITIONS							
WORKING CAPITAL	1,497	1,385	235	3,170	460	2,273	4,117
DEDUCTIONS							
ACCELERATED AMORTIZATION	8	5	1	29	4	23	42
LIBERALIZED DEPRECIATION	4,346	4,918	580	5,522	823	4,779	8,104
RECOVERABLE FUEL COST	0	0	0	0	0	0	0
TOTAL RATE BASE	50,455	53,242	6,850	75,381	11,160	64,012	109,619
REVENUE							
SALES	13,431	17,722	2,300	29,633	4,803	18,244	28,696
OTHER	84	54	37	213	31	237	2,819
TOTAL REVENUE	13,515	17,776	2,337	29,846	4,834	18,481	31,515
EXPENSES							
OPERATION AND MAINT EXP	8,256	7,896	1,300	12,426	1,830	11,917	22,871
DEPRECIATION AND AMORT	1,871	2,812	308	2,872	424	2,427	4,201
TAXES OTH THN INCOME TAX	580	698	91	365	55	672	1,153
INCOME TAXES	-562	551	35	2,961	644	-247	-1,903
PROV FOR DEFERRED INC TAX	794	1,059	98	2,176	321	362	813
INC TX DEF IN PRIOR YR	-52	-37	-9	-165	-24	-135	-241
INVESTMENT TAX CREDIT	-28	-32	-4	-36	-5	-31	-52
GAIN FROM DISPOSITION OF UTL PROP	0	0	0	0	0	0	0
TOTAL EXPENSES	10,859	12,948	1,820	20,599	3,245	14,965	26,841
NET OPERATING INCOME	2,657	4,828	517	9,247	1,589	3,517	4,674
RATE OF RETURN	5.27%	9.07%	7.54%	12.27%	14.24%	5.49%	4.26%
INDEX OF RETURN	82	142	118	192	223	86	67
DEVIATION	-1.12	2.68	1.16	5.88	7.85	-.89	-2.12
REVENUE SUBSIDY	-1,149	2,899	161	9,003	1,780	-1,162	-4,729
PROPOSED OPERATING INCOME	$ 3,019	$ 5,053	$ 570	$ 9,248	$ 1,589	$ 5,980	$ 6,992
PROPOSED RATE OF RETURN	5.98%	9.49%	8.32%	12.27%	14.24%	9.34%	6.38%
PROPOSED INDEX OF RETURN	47	75	66	97	112	74	50
PROPOSED DEVIATION	-6.72	-3.21	-4.38	-.43	1.54	-3.36	-6.32
PROPOSED REVENUE SUBSIDY	-6,884	-3,471	-610	-661	348	-4,367	-14,077

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Schedule 4
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PHILADELPHIA ELECTRIC COMPANY

Rate of Return Summary of Noncoincident Peak
Cost of Service for Various Weather Adjustments
Twelve Months Ending June 30, 1986

		Present				Proposed			
Line	Rate Schedule	PECO EDH (1)	1980-1983 EDH Average (2)	1985 EDH (3)	EDH=213 (4)	PECO EDH (5)	1980-1983 EDH Average (6)	1985 EDH (7)	EDH=213 (8)
1	HT	6.66%	7.38%	7.43%	7.46%	14.50%	15.75%	15.85%	15.90%
2	PD	6.78	7.50	7.55	7.58	13.32	14.48	14.56	14.61
3	GS	10.30	9.64	9.74	9.55	18.19	17.15	17.31	17.02
4	RH	1.80	2.19	2.22	2.24	5.41	6.05	6.10	6.12
5	R	6.11	5.30	5.21	5.19	12.11	10.80	10.66	10.64
6	OP	0.54	0.44	0.46	0.75	2.03	1.89	1.92	2.31
7	SLP	4.95	5.23	5.25	5.27	5.64	5.95	5.97	5.98
8	SLS	8.79	9.04	9.06	9.07	9.21	9.46	9.48	9.49
9	Other SL	7.05	7.49	7.53	7.54	7.79	8.26	8.30	8.32
10	Other Utilities	11.11	12.14	12.22	12.27	11.11	12.15	12.23	12.27
11	Interdepartmental	12.94	14.10	14.19	14.24	12.94	14.10	14.19	14.24
12	SEPTA	4.85	5.43	5.47	5.49	8.43	9.25	9.31	9.34
13	AMTRAK	3.69	4.20	4.24	4.26	5.65	6.30	6.35	6.38
14	Total Company	6.39%	6.39%	6.39%	6.39%	12.70%	12.70%	12.70%	12.70%

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PHILADELPHIA ELECTRIC COMPANY

Revenue Subsidy Summary of Noncoincident Peak
Cost of Service for Various Weather Adjustments
Twelve Months Ending June 30, 1986

		Present				Proposed			
Line	Rate Schedule	PECO EDH (000) (1)	1980-1983 EDH Average (000) (2)	1985 EDH (000) (3)	EDH=213 (000) (4)	PECO EDH (000) (5)	1980-1983 EDH Average (000) (6)	1985 EDH (000) (7)	EDH=213 (000) (8)
1	HT	$ 12,622	$ 42,177	$ 44,278	$ 45,408	$ 82,242	$ 130,178	$ 133,585	$ 135,418
2	PD	4,506	11,958	12,487	12,771	7,070	19,114	19,969	20,428
3	GS	64,334	56,062	57,401	54,910	90,295	76,880	79,041	75,014
4	RH	(59,442)	(50,910)	(50,307)	(49,983)	(94,451)	(80,701)	(79,728)	(79,205)
5	R	(12,383)	(53,469)	(58,449)	(59,180)	(26,400)	(92,911)	(100,966)	(102,152)
6	OP	(11,633)	(12,147)	(12,047)	(10,729)	(21,236)	(22,072)	(21,911)	(19,782)
7	SLP	(1,528)	(1,187)	(1,162)	(1,149)	(7,494)	(6,943)	(6,905)	(6,884)
8	SLS	2,657	2,876	2,891	2,899	(3,862)	(3,510)	(3,485)	(3,471)
9	Other SL	96	154	159	161	(714)	(620)	(613)	(610)
10	Other Utilities	7,792	8,883	8,961	9,003	(2,625)	(854)	(729)	(661)
11	Interdepartmental	1,601	1,762	1,773	1,780	60	320	338	348
12	SEPTA	(2,147)	(1,259)	(1,196)	(1,162)	(5,965)	(4,525)	(4,423)	(4,367)
13	AMTRAK	(6,475)	(4,901)	(4,789)	(4,729)	(16,919)	(14,357)	(14,175)	(14,077)
14	Total Company	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

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Schedule 5
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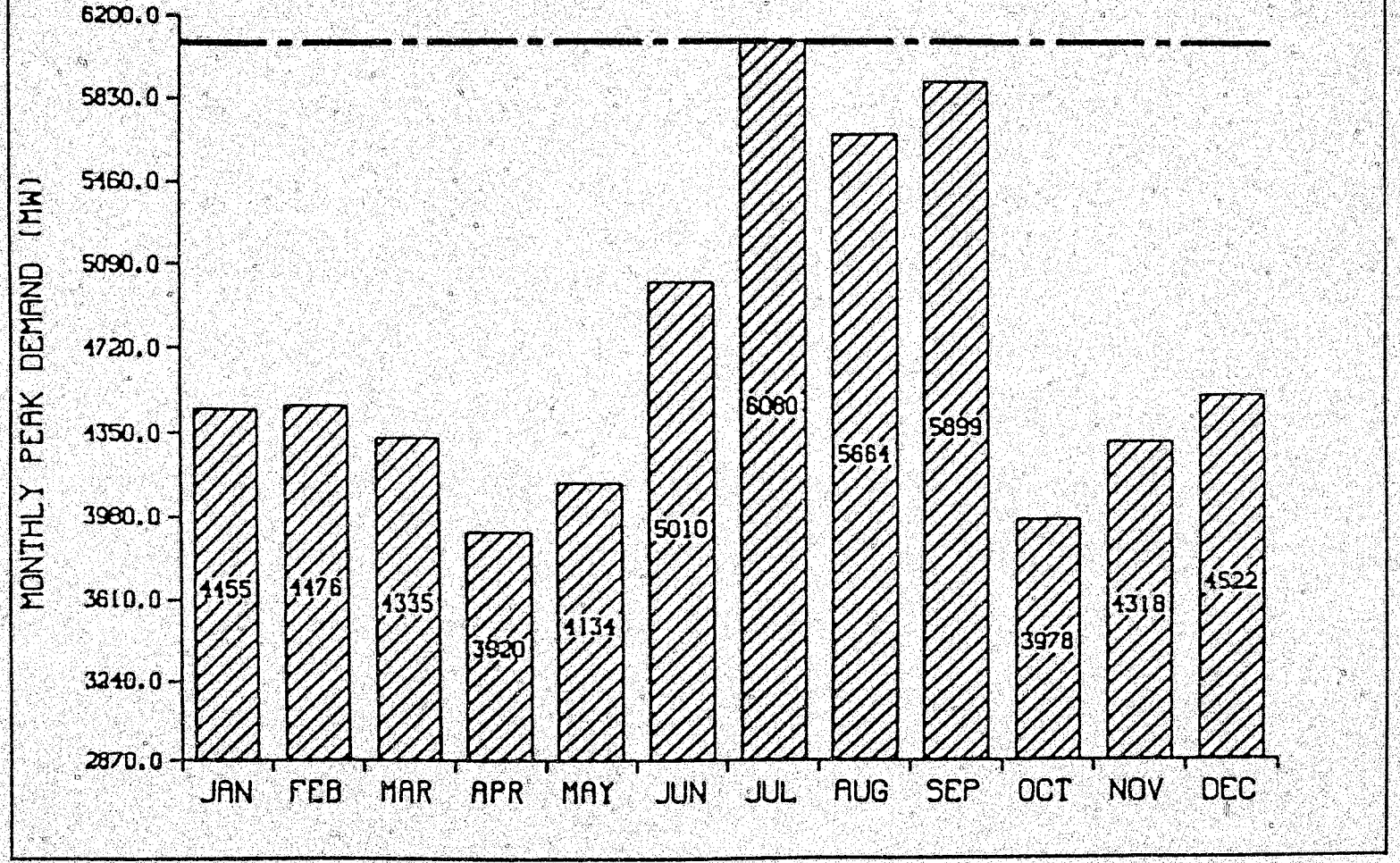
INDEX TO APPENDIX B
OF THE TESTIMONY OF MELVIN BLOOM

Reference	Description
Charts 1-5	Analysis of PECO Monthly Peak Demands
Schedule 1 and Charts 6-10	PECO Monthly Peak Demands as a Percent of the Annual System Peak
Charts 11-15	Analysis of PJM Monthly Peak Demands as a Percent of Annual System Peak
Schedule 2 and Charts 16-21	Analysis of PJM Monthly Reserve Margins
Schedule 3 and Charts 22-27	Analysis of PJM Monthly Capacity Margins

PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS

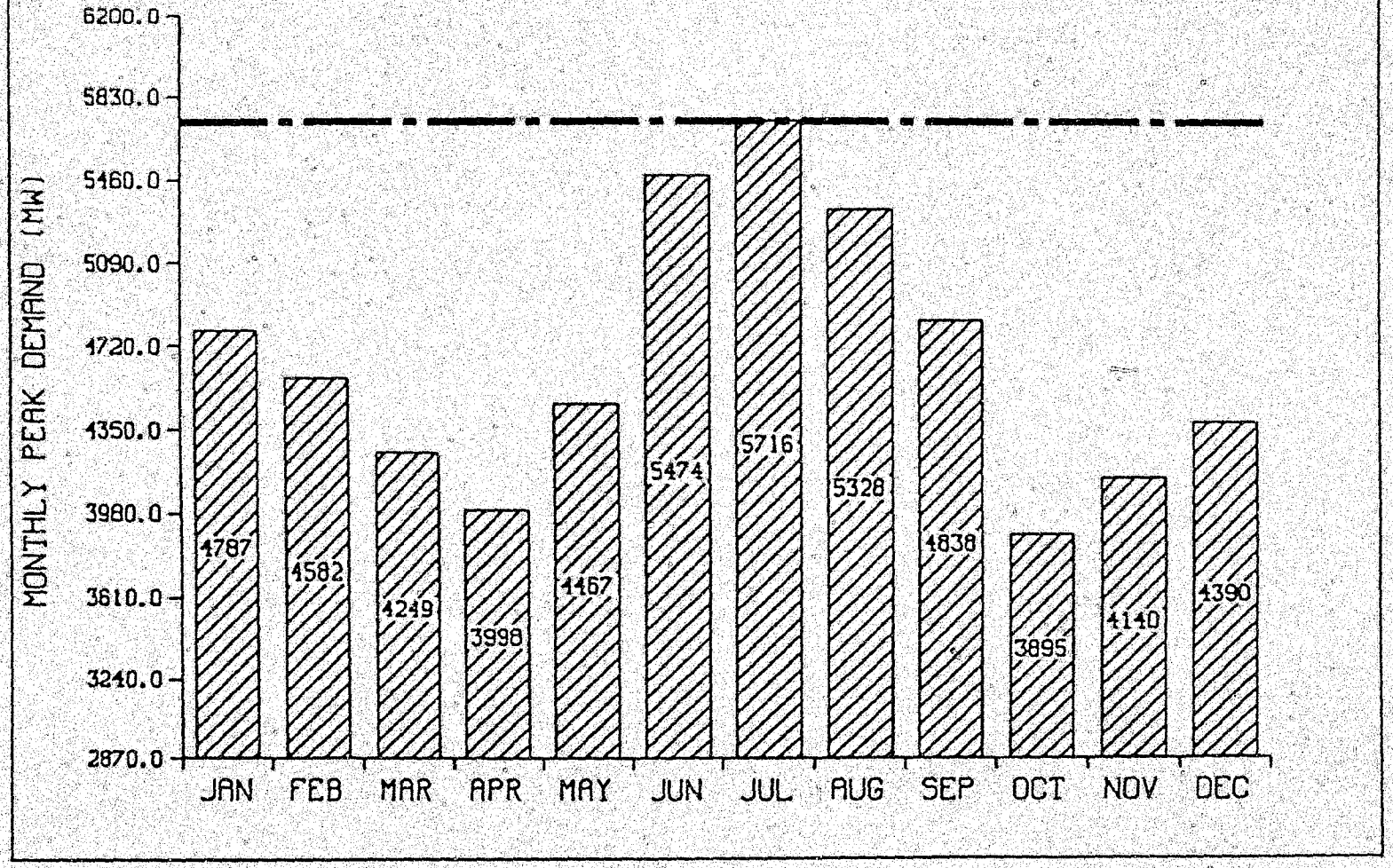
YEAR ENDED DECEMBER 31, 1980



Appendix B
Chart 1

PHILADELPHIA ELECTRIC COMPANY

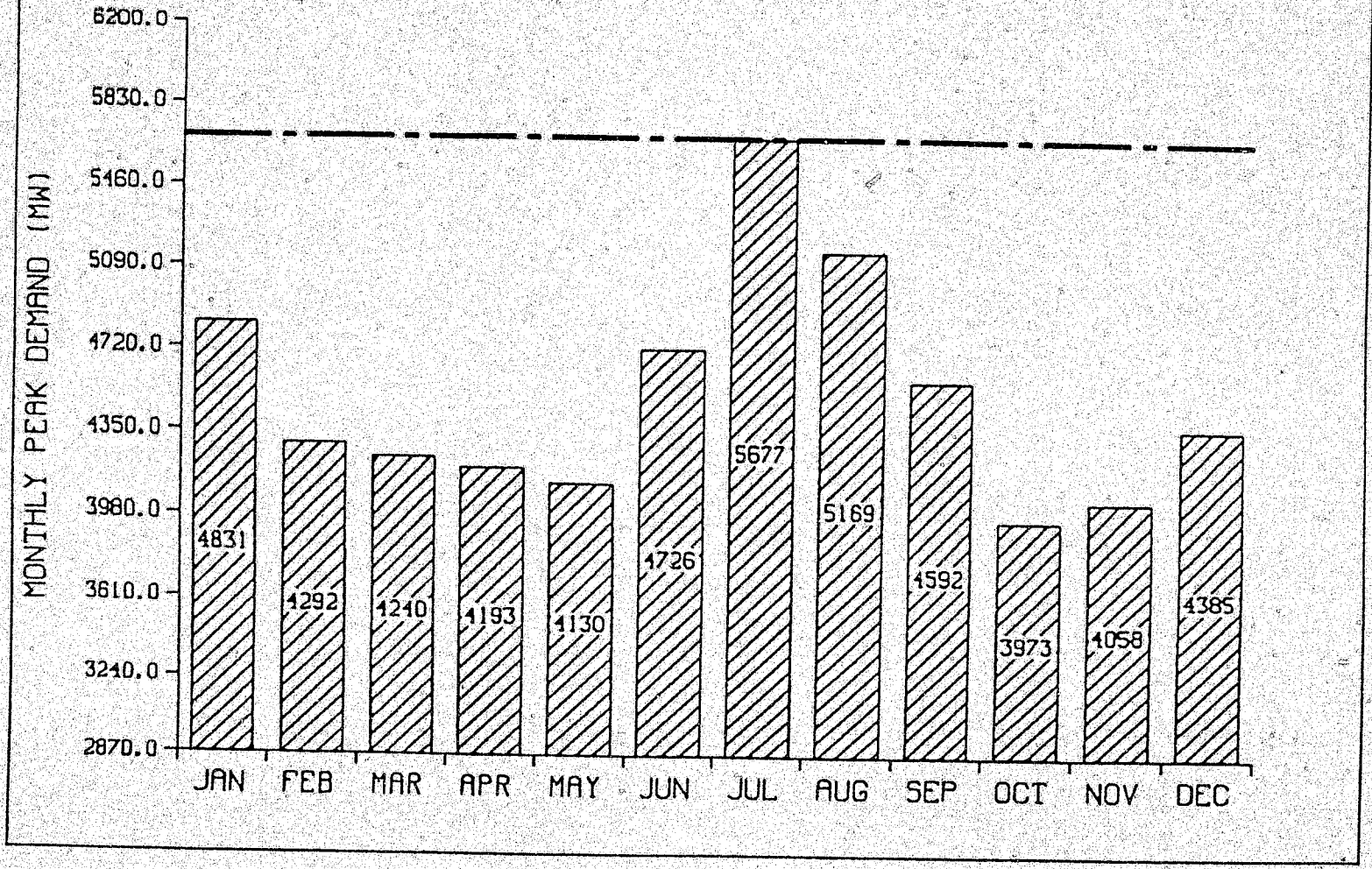
ANALYSIS OF MONTHLY PEAK DEMANDS
YEAR ENDED DECEMBER 31, 1981



Appendix B
Chart 2

PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS
YEAR ENDED DECEMBER 31, 1982

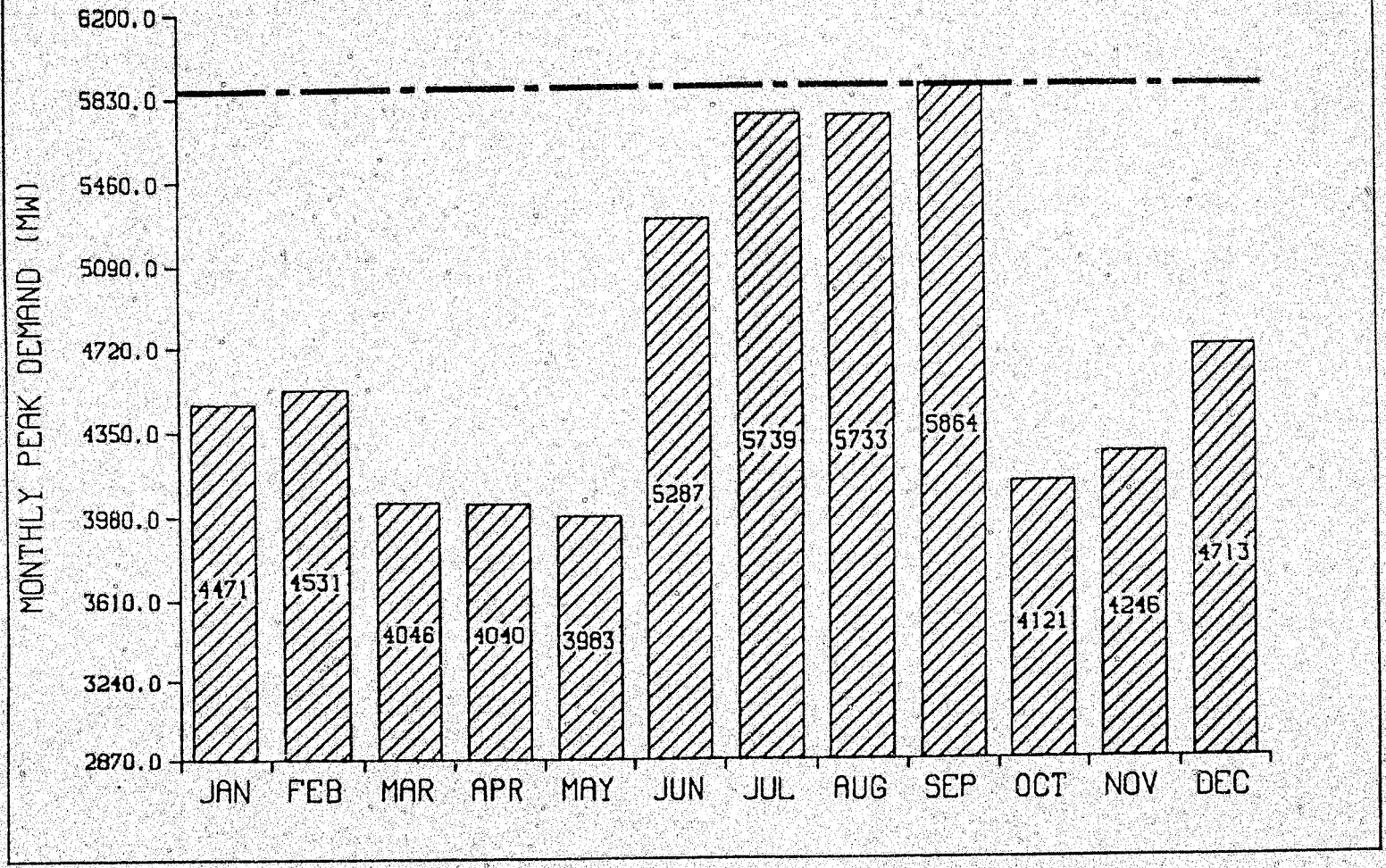


Appendix B
Chart 3

PHILADELPHIA ELECTRIC COMPANY

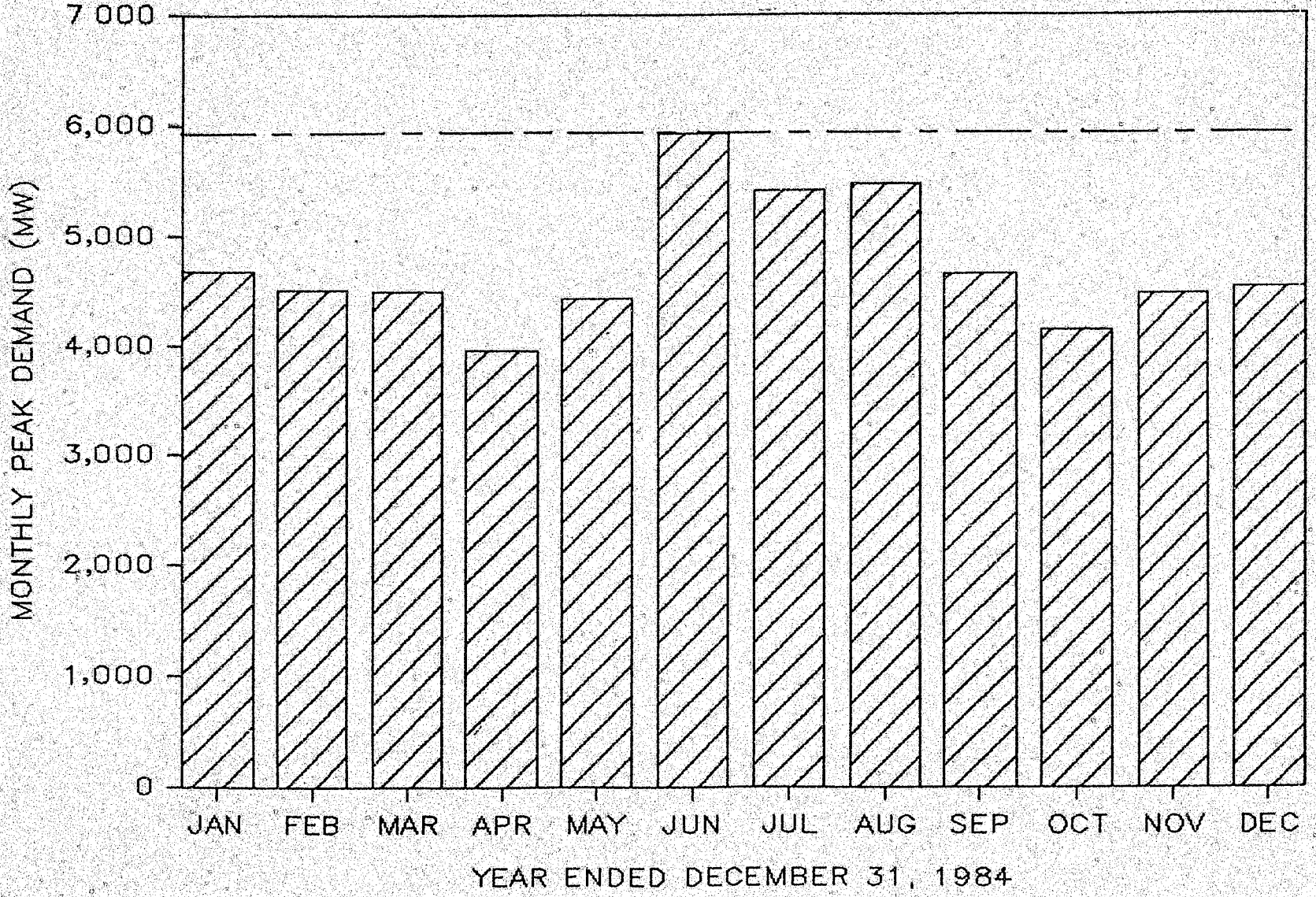
ANALYSIS OF MONTHLY PEAK DEMANDS

YEAR ENDED DECEMBER 31, 1983



PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS



YEAR ENDED DECEMBER 31, 1984

Appendix B
Chart 5

PHILADELPHIA ELECTRIC COMPANY

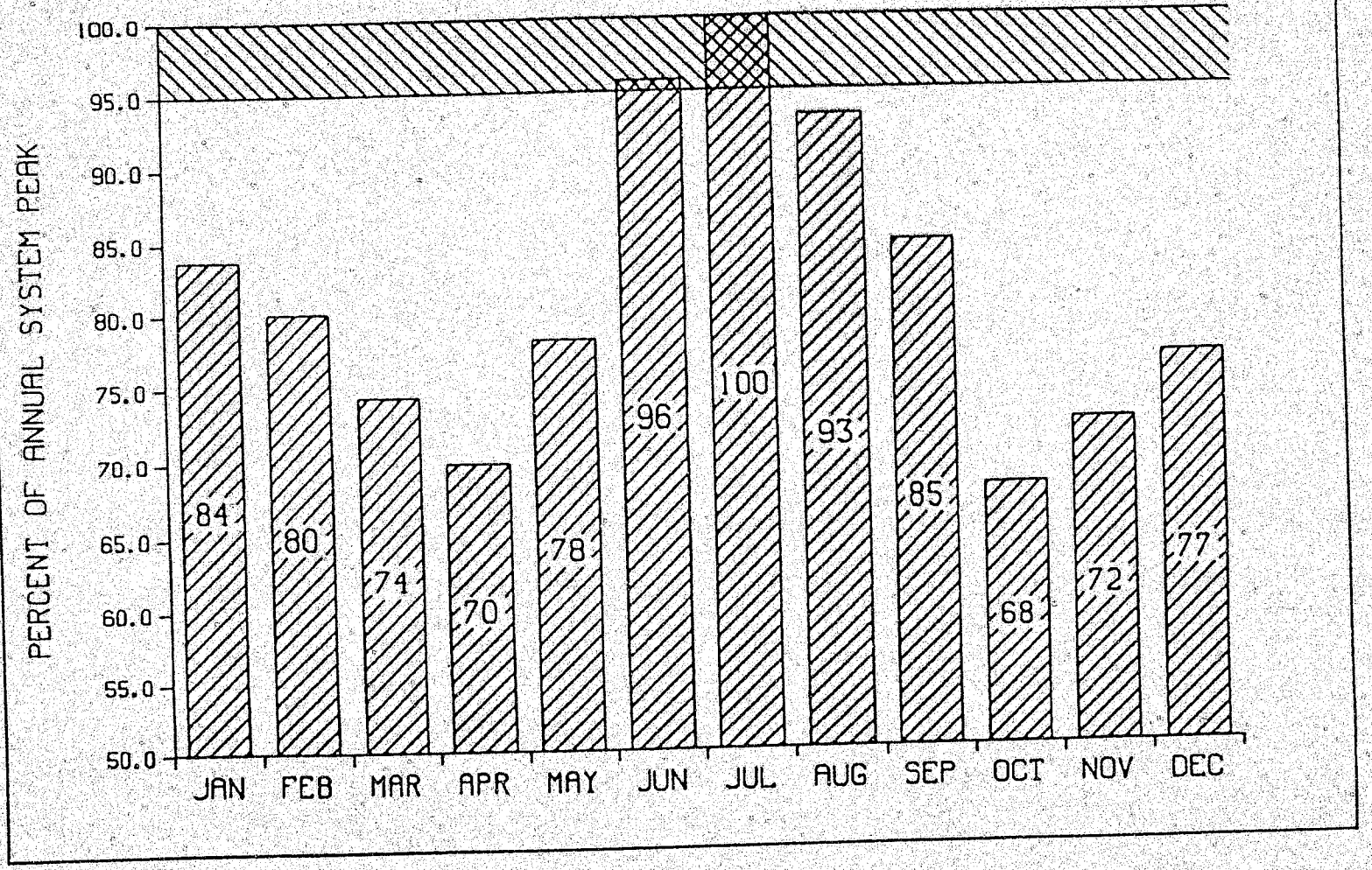
Monthly Peak Demands as a
Percent of the Annual System Peak

Line	Month	1979 (1)	1980 (2)	1981 (3)	1982 (4)	1983 (5)	1984 (6)
1	January	83%	73%	84%	85%	76%	79%
2	February	83	74	80	76	77	76
3	March	76	71	74	75	69	76
4	April	73	64	70	74	69	67
5	May	81	68	78	73	68	75
6	June	88	82	96	83	90	100
7	July	96	100	100	100	98	91
8	August	100	93	93	91	98	92
9	September	94	97	85	81	100	79
10	October	73	65	68	70	70	70
11	November	76	71	72	71	72	76
12	December	82	74	77	77	80	77
13	Ratio of Maximum to Minimum Monthly Peak	1.38	1.55	1.47	1.43	1.47	1.49
14	Ratio of Maximum to Average Monthly Peak	1.19	1.28	1.23	1.26	1.24	1.25
15	Annual Load Factor	60%	56%	60%	64%	58%	58%
16	Peak Load, MW	5,627	6,080	5,716	5,677	5,864	5,925

Appendix B
Chart 6

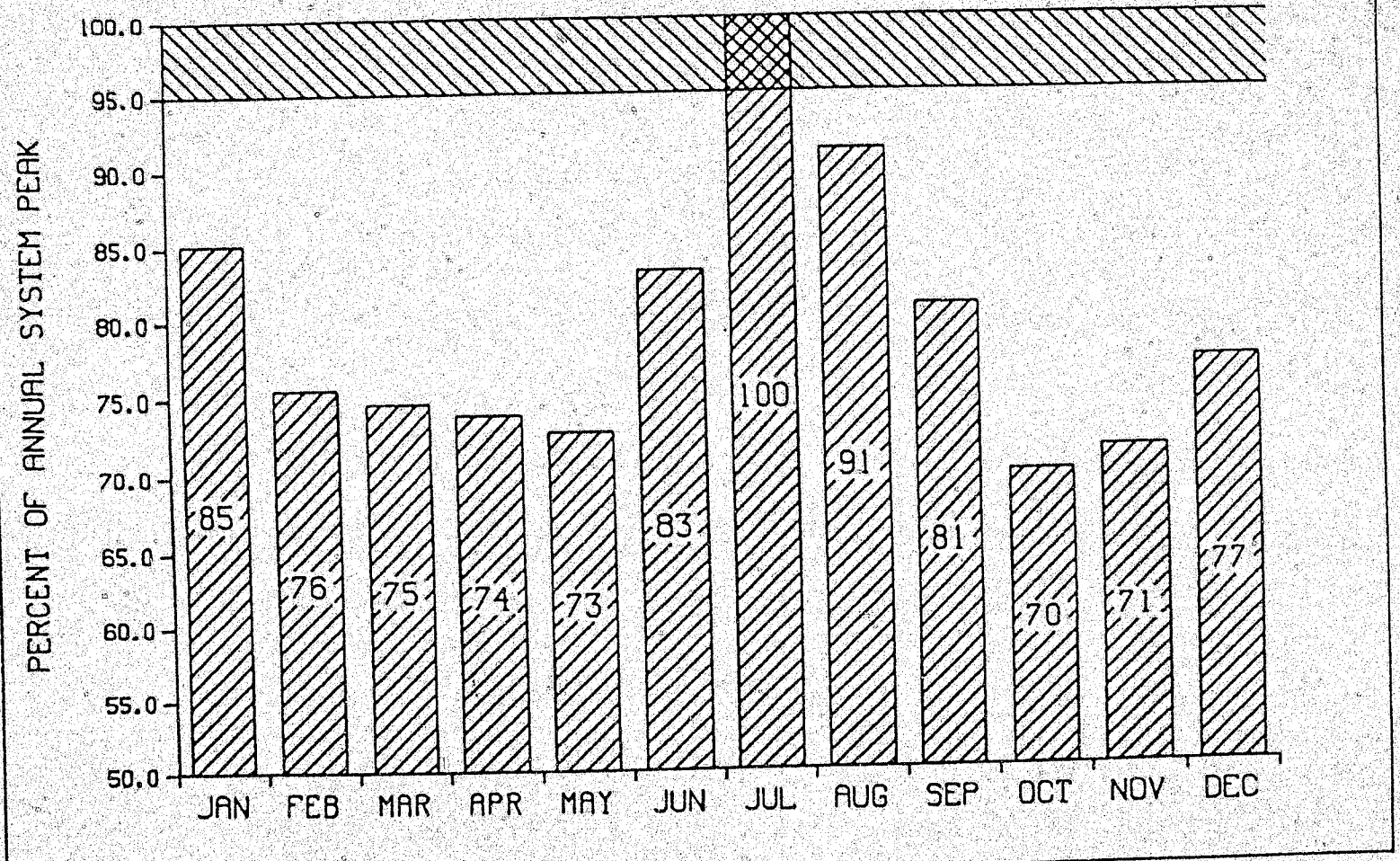
PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1981



PHILADELPHIA ELECTRIC COMPANY

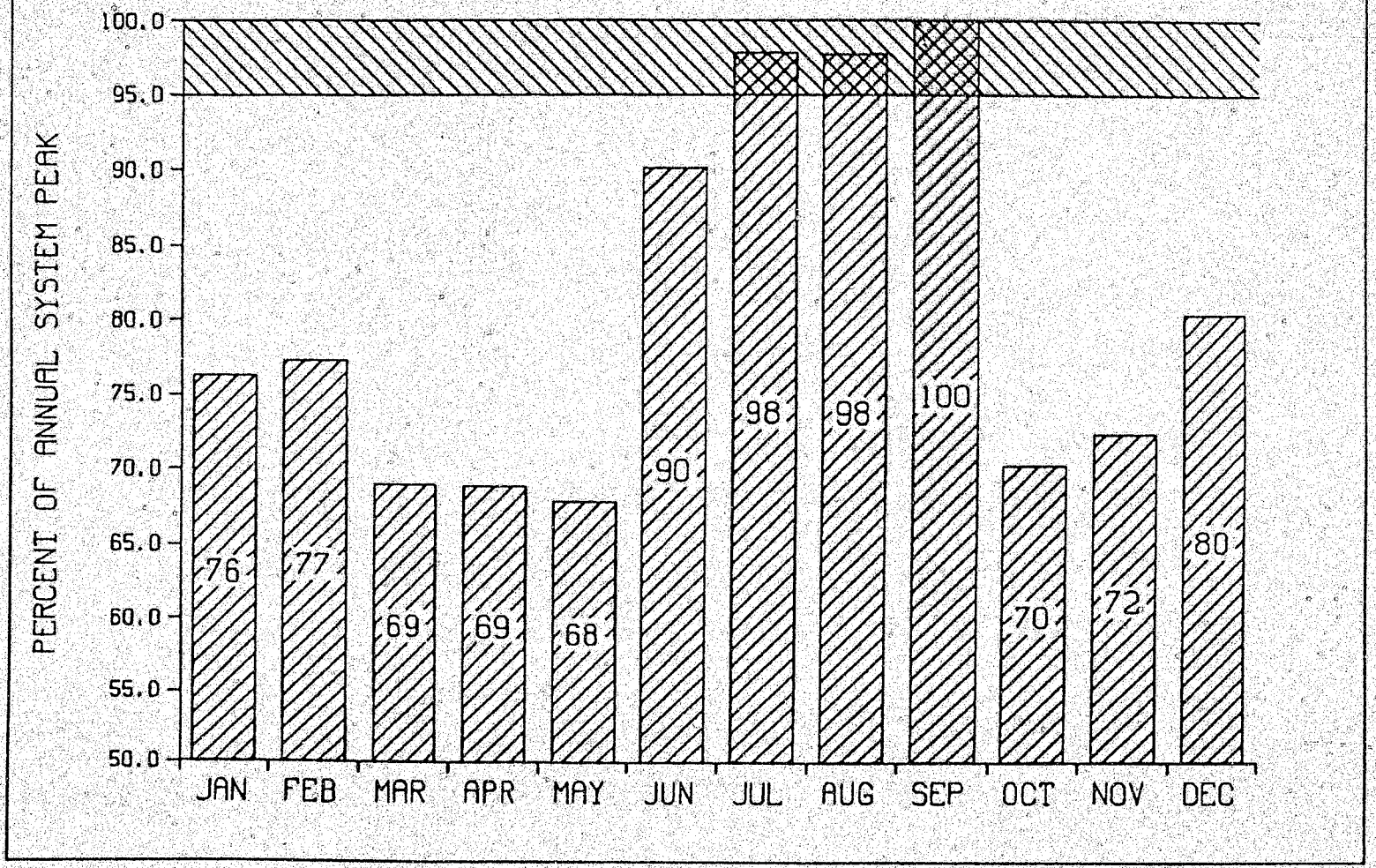
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1982



Appendix B
Chart 8

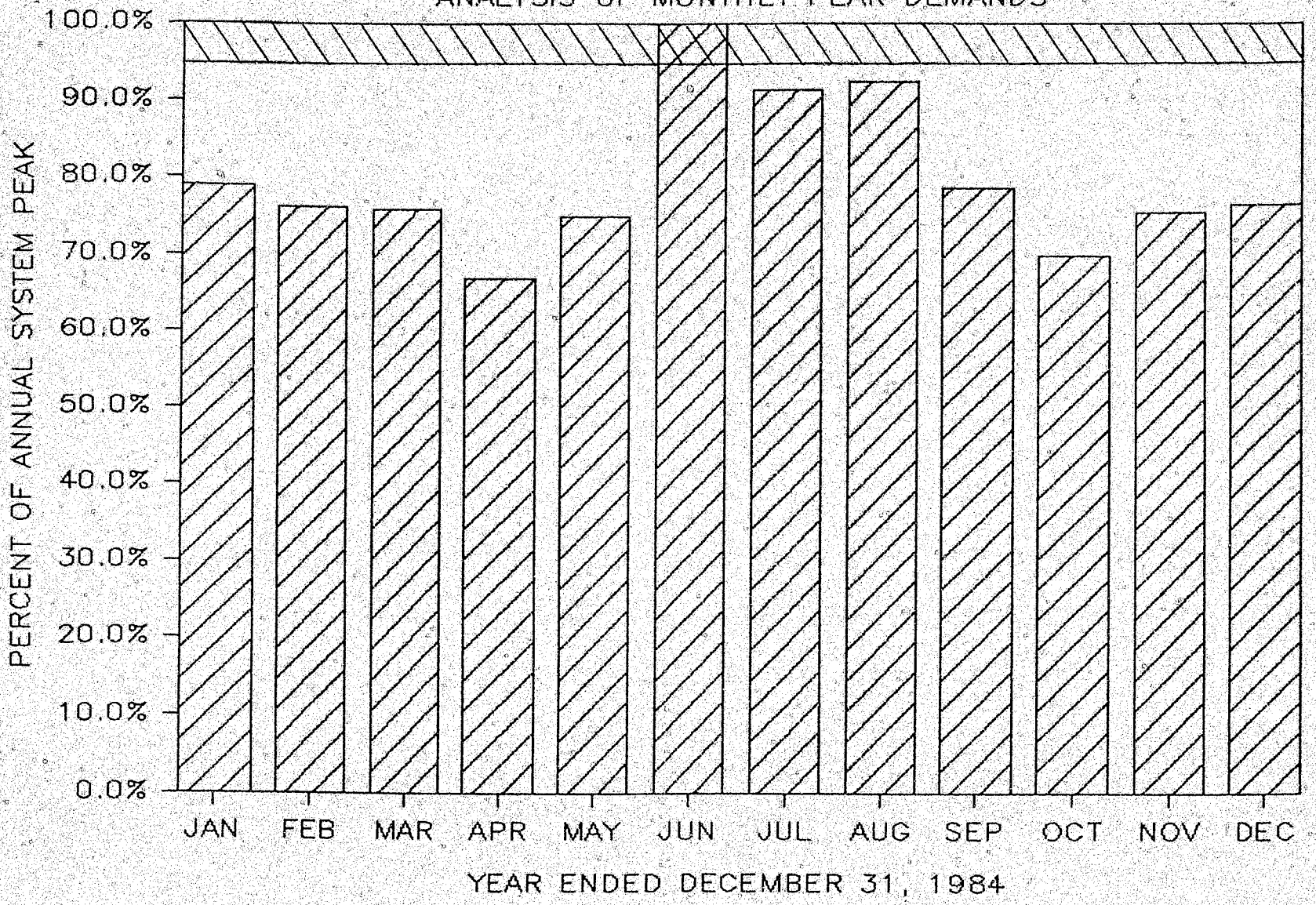
PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1983



PHILADELPHIA ELECTRIC COMPANY

ANALYSIS OF MONTHLY PEAK DEMANDS

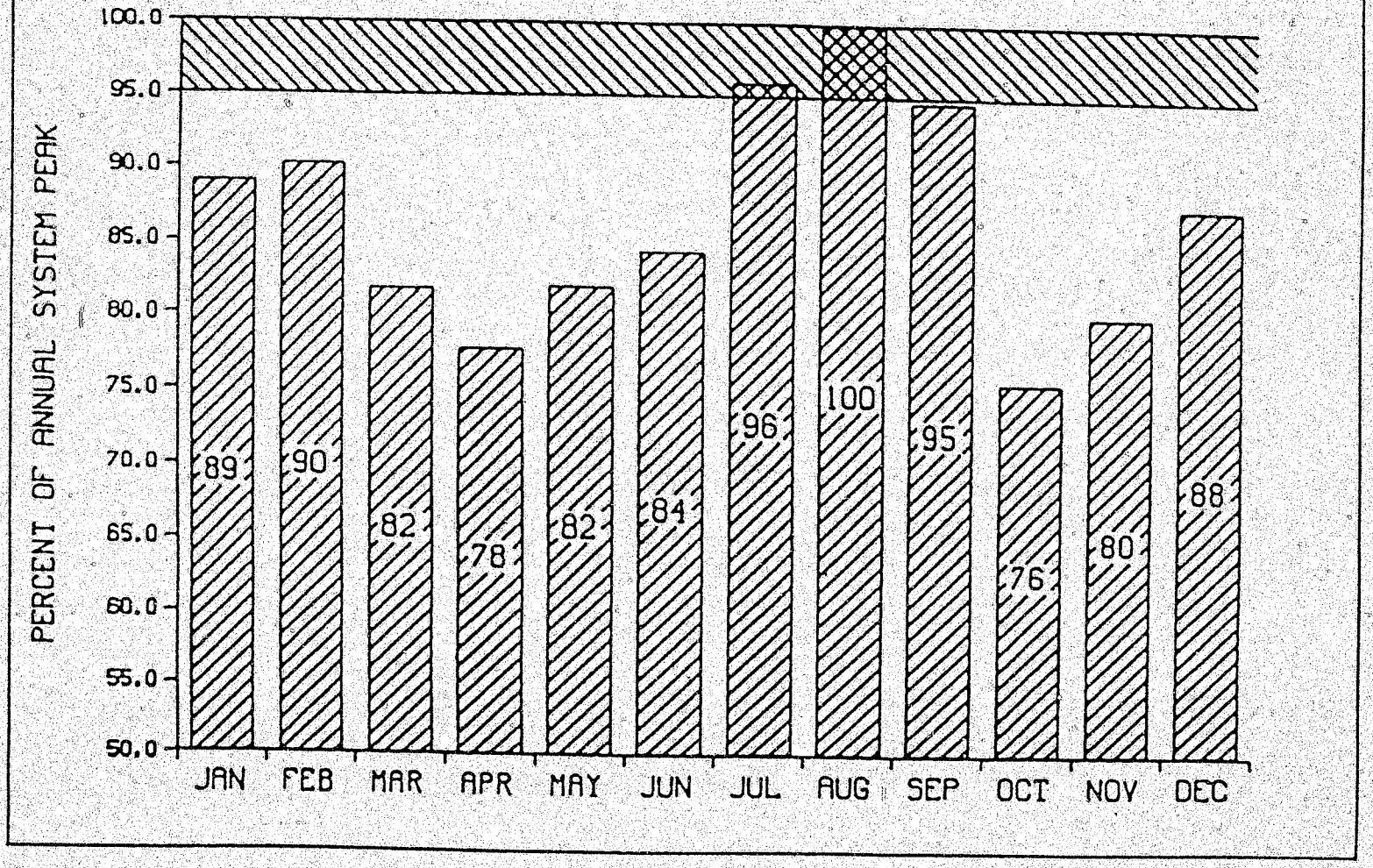


YEAR ENDED DECEMBER 31, 1984

Appendix B
Chart 10

PJM INTERCONNECTION

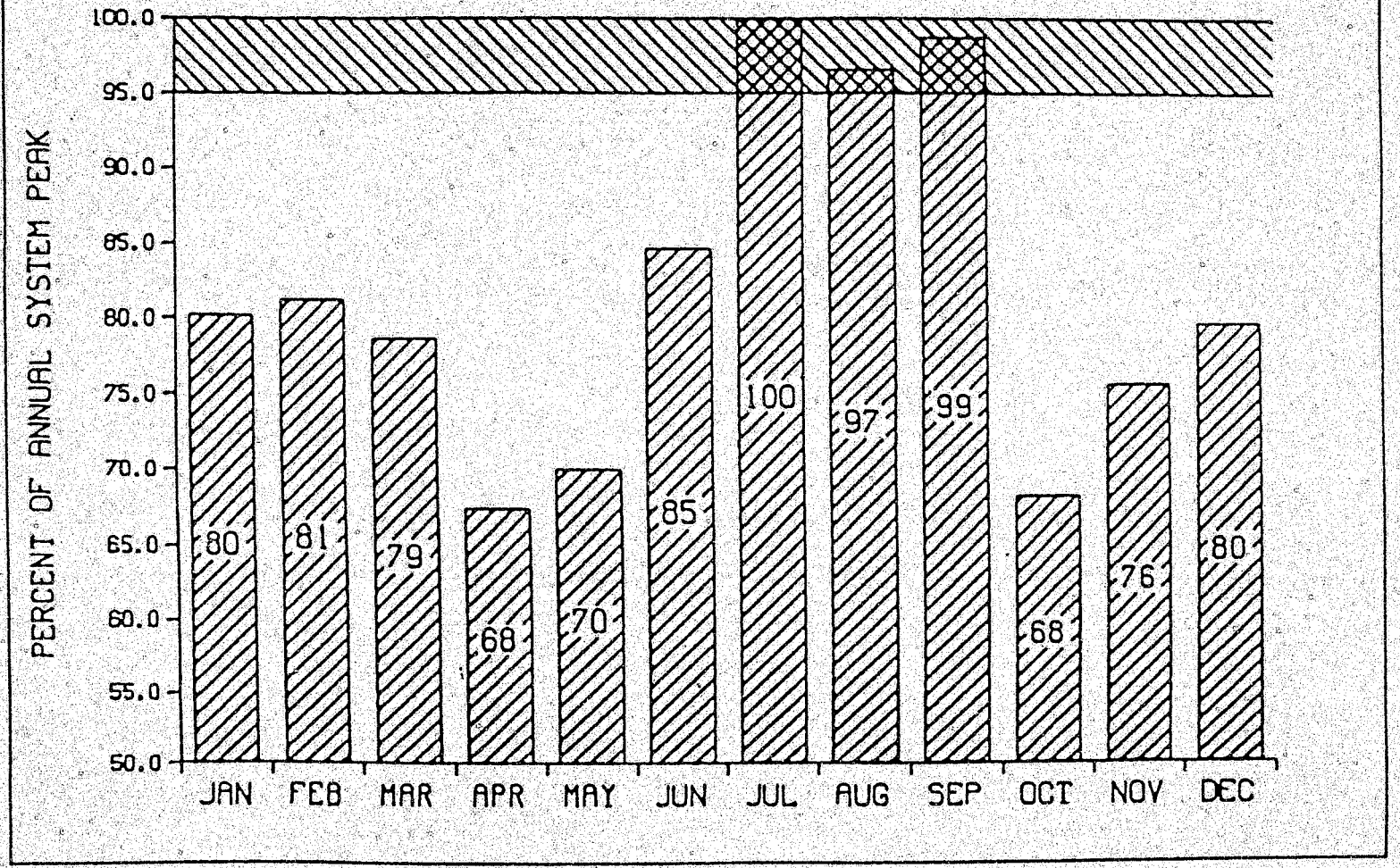
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1979



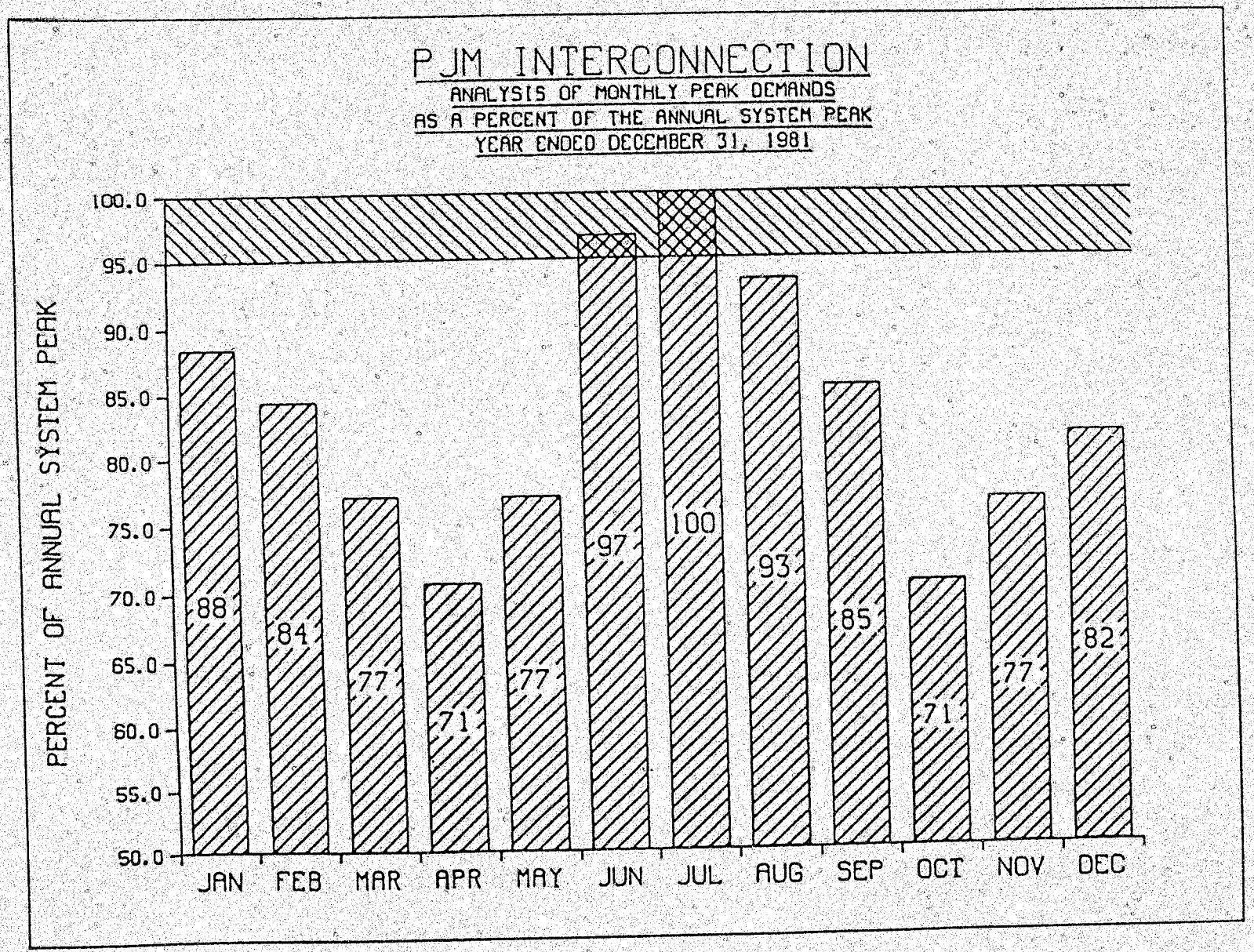
Appendix B
Chart 11

PJM INTERCONNECTION

ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1980

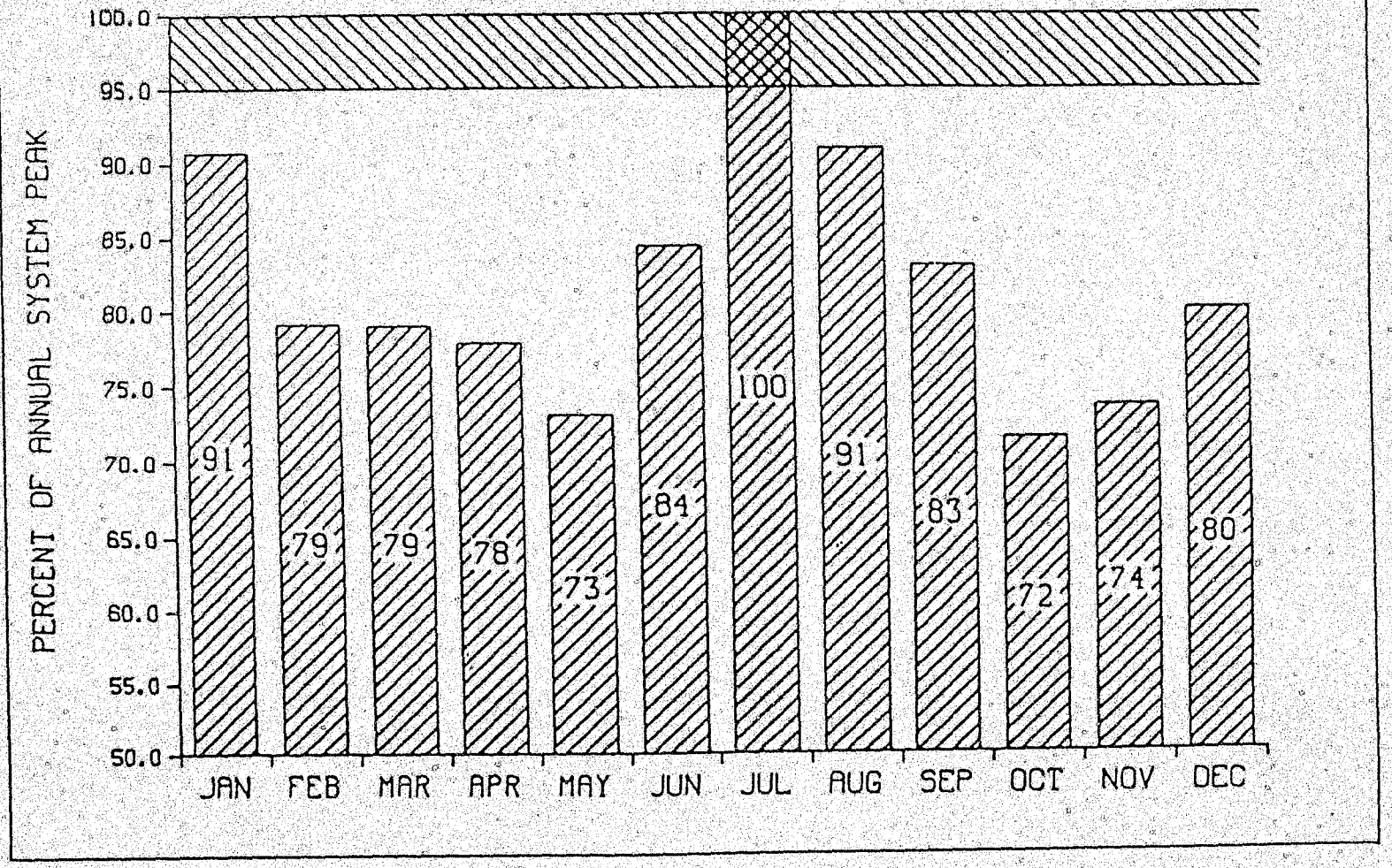


Appendix B
Chart 12


PJM INTERCONNECTION
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1981
PERCENT OF ANNUAL SYSTEM PEAK
100.0
95.0
90.0
85.0
80.0
75.0
70.0
65.0
60.0
55.0
50.0
88
84
77
71
77
97
100
93
85
71
77
82
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC

PJM INTERCONNECTION

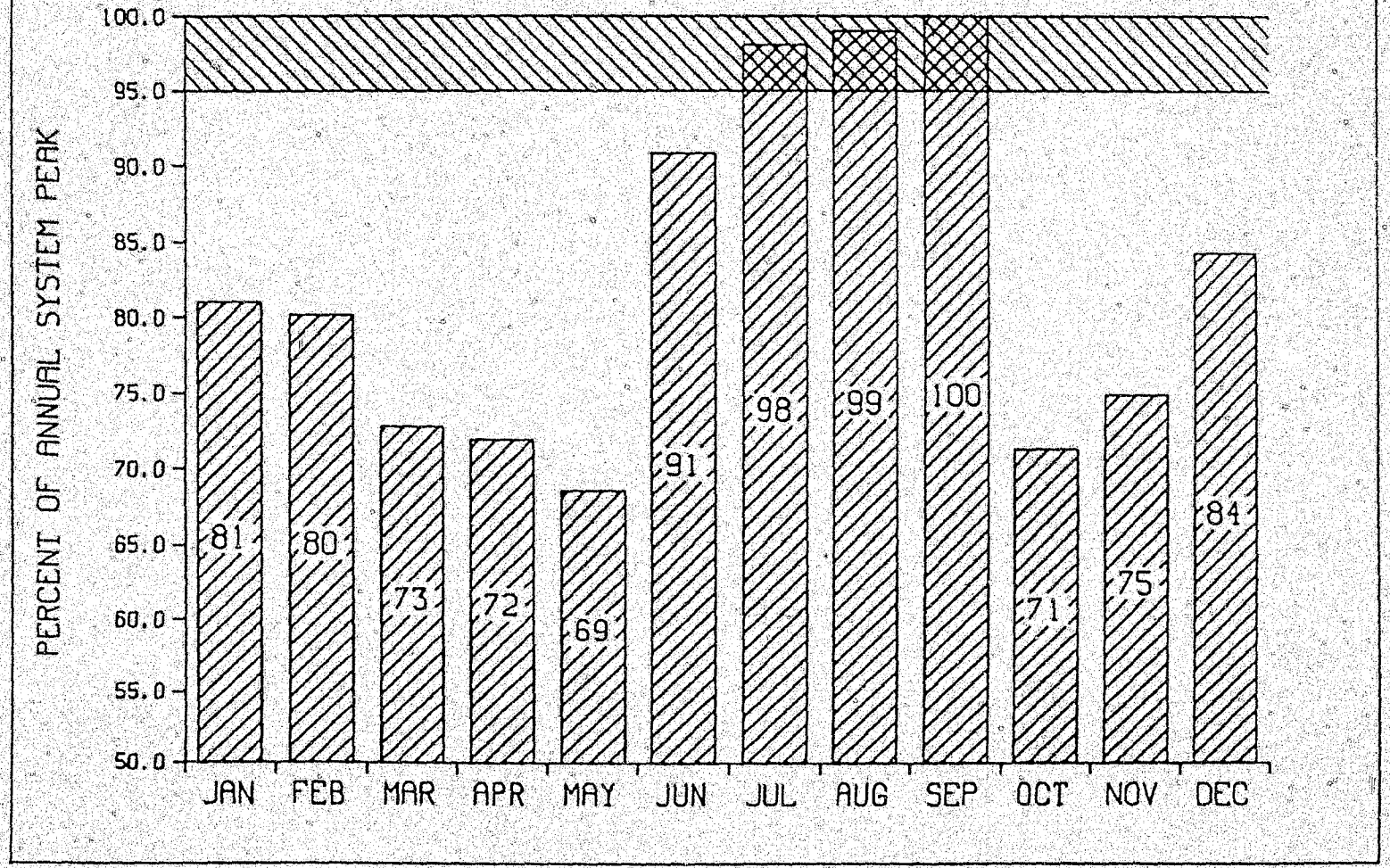
ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1982



Appendix B
Chart 14

PJM INTERCONNECTION

ANALYSIS OF MONTHLY PEAK DEMANDS
AS A PERCENT OF THE ANNUAL SYSTEM PEAK
YEAR ENDED DECEMBER 31, 1983



Appendix B
Chart 15

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1979

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,698	44,660	44,643	44,613	44,613	44,613	44,613	44,613	44,613	44,623	44,631	44,631
System Demand (MW)	28,171	28,529	25,883	24,634	25,955	26,730	30,371	31,654	29,957	23,970	25,385	27,732
Reserve Margin (MW)	16,527	16,131	18,760	19,979	18,658	17,883	14,242	12,959	14,656	20,653	19,246	16,899
Reserve Margin as a Percent of System Demand	58.7%	56.5%	72.5%	81.1%	71.9%	66.9%	46.9%	40.9%	48.9%	86.2%	75.8%	60.9%

ce: Form 12-E-2 Reports.

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1980

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,492	44,499	44,498	44,496	44,496	44,715	44,752	44,753	44,753	44,994	44,994	44,994
System Demand (MW)	27,621	27,967	27,100	23,243	24,130	29,153	34,420	33,247	33,972	23,533	26,072	27,448
Reserve Margin (MW)	16,871	16,532	17,398	21,253	20,366	15,562	10,332	11,506	10,781	21,461	18,922	17,546
Reserve Margin as a Percent of System Demand	61.1%	59.1%	64.2%	91.4%	84.4%	53.4%	30.0%	34.6%	31.7%	91.2%	72.6%	63.9%

ce: Form 12-E-2 Reports.

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1981

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,900	44,870	44,828	44,840	44,840	44,625	44,627	44,627	44,627	45,393	45,393	45,393
System Demand (MW)	29,625	28,313	25,870	23,715	25,853	32,448	33,528	31,292	28,608	23,680	25,735	27,393
Reserve Margin (MW)	15,275	16,557	18,958	21,125	18,987	12,177	11,099	13,335	16,019	21,713	19,658	18,000
Reserve Margin as a Percent of System Demand	51.6%	58.5%	73.3%	89.1%	73.4%	37.5%	33.1%	42.6%	56.0%	91.7%	76.4%	65.7%

e: ERA Form 119-M.

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Schedule 2
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PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1982

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	45,570	45,547	45,859	45,859	45,781	45,781	45,796	45,796	45,772	45,783	45,774	45,774
System Demand (MW)	30,621	26,734	26,683	26,302	24,685	28,469	33,741	30,668	28,042	24,147	24,883	27,062
Reserve Margin (MW)	14,949	18,813	19,176	19,557	21,096	17,312	12,055	15,128	17,730	21,636	20,891	18,712
Reserve Margin as a Percent of System Demand	48.8%	70.4%	71.9%	74.4%	85.5%	60.8%	35.7%	49.3%	63.2%	89.6%	84.0%	69.1%

: ERA Form 119-M.

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PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1983

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	45,794	45,794	45,802	45,814	45,814	46,864	46,712	46,704	46,704	46,734	46,734	47,056
System Demand (MW)	28,092	27,813	25,278	24,994	23,786	31,520	34,021	34,346	34,678	24,742	25,922	29,241
Reserve Margin (MW)	17,702	17,981	20,524	20,820	22,028	15,344	12,691	12,358	12,026	21,992	20,812	17,815
Reserve Margin as a Percent of System Demand	63.0%	64.6%	81.2%	83.3%	92.6%	48.7%	37.3%	36.0%	34.7%	88.9%	80.3%	60.9%

ce: IR-PAIEUG-1-3.

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1984

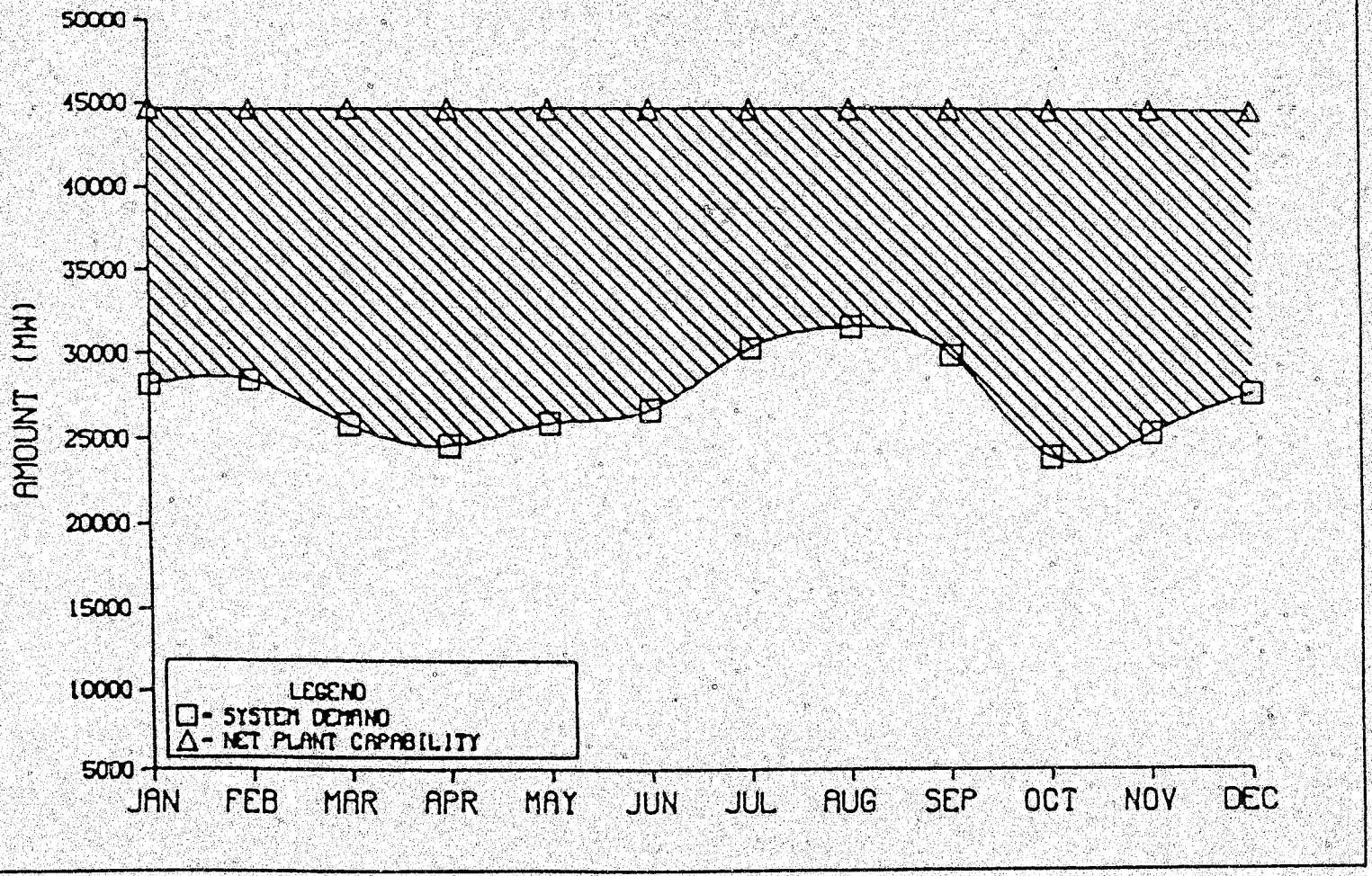
Line	Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
1	Net Plant Capability (MW)	48,604	48,509	48,367	48,285	48,057	45,899	46,833	46,190	47,371	47,034	47,639	47,652
2	System Demand (MW)	29,658	28,332	28,261	24,704	26,486	35,319	33,013	33,229	28,694	25,239	27,786	28,539
3	Reserve Margin (MW)	18,946	20,177	20,106	23,581	21,571	10,580	13,820	12,961	18,677	21,795	19,853	19,113
4	Reserve Margin as a Percent of System Demand	64.0%	71.2%	71.1%	96.0%	81.4%	30.0%	42.0%	39.0%	65.1%	86.4%	71.4%	67.0%

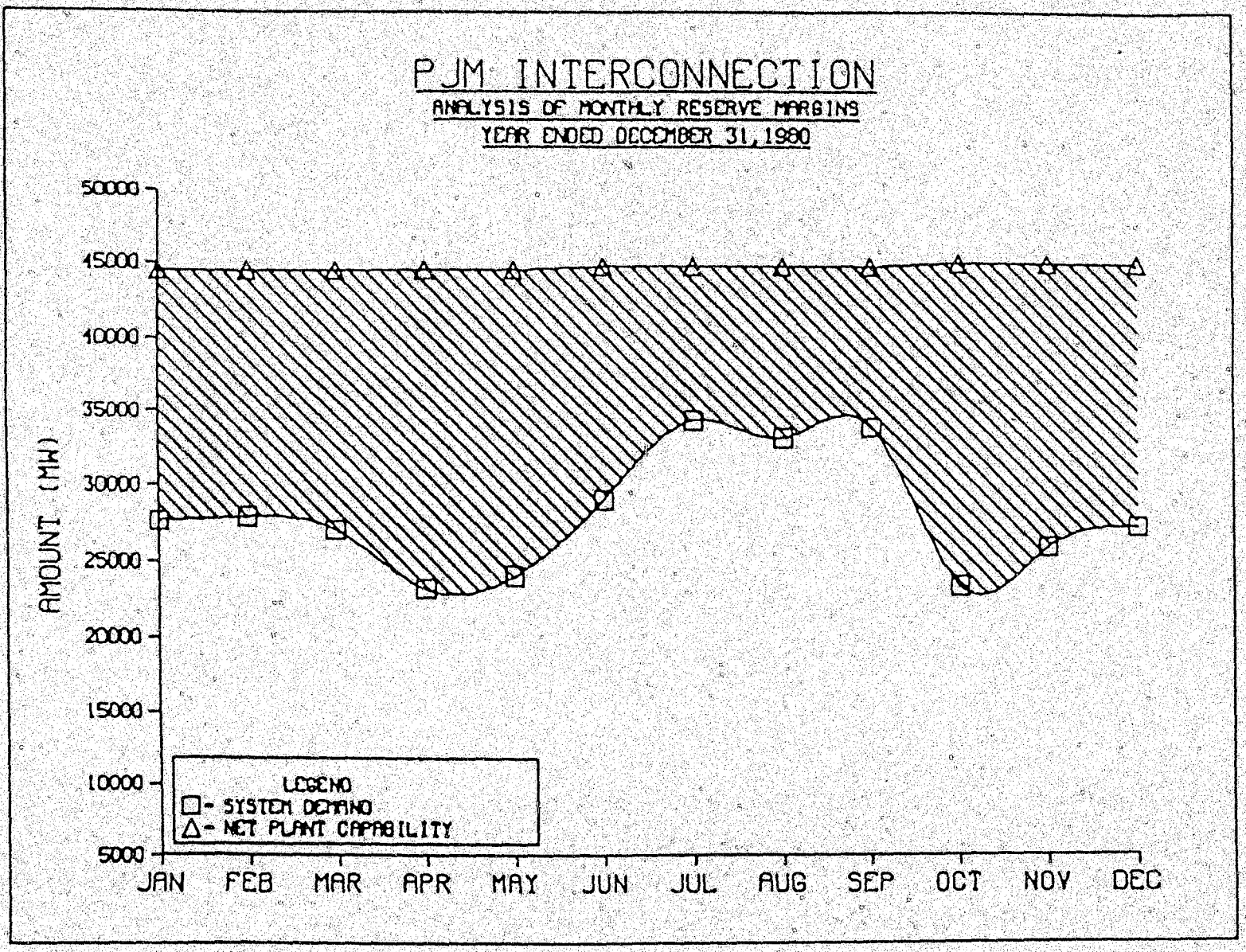
Appendix B
Schedule 2
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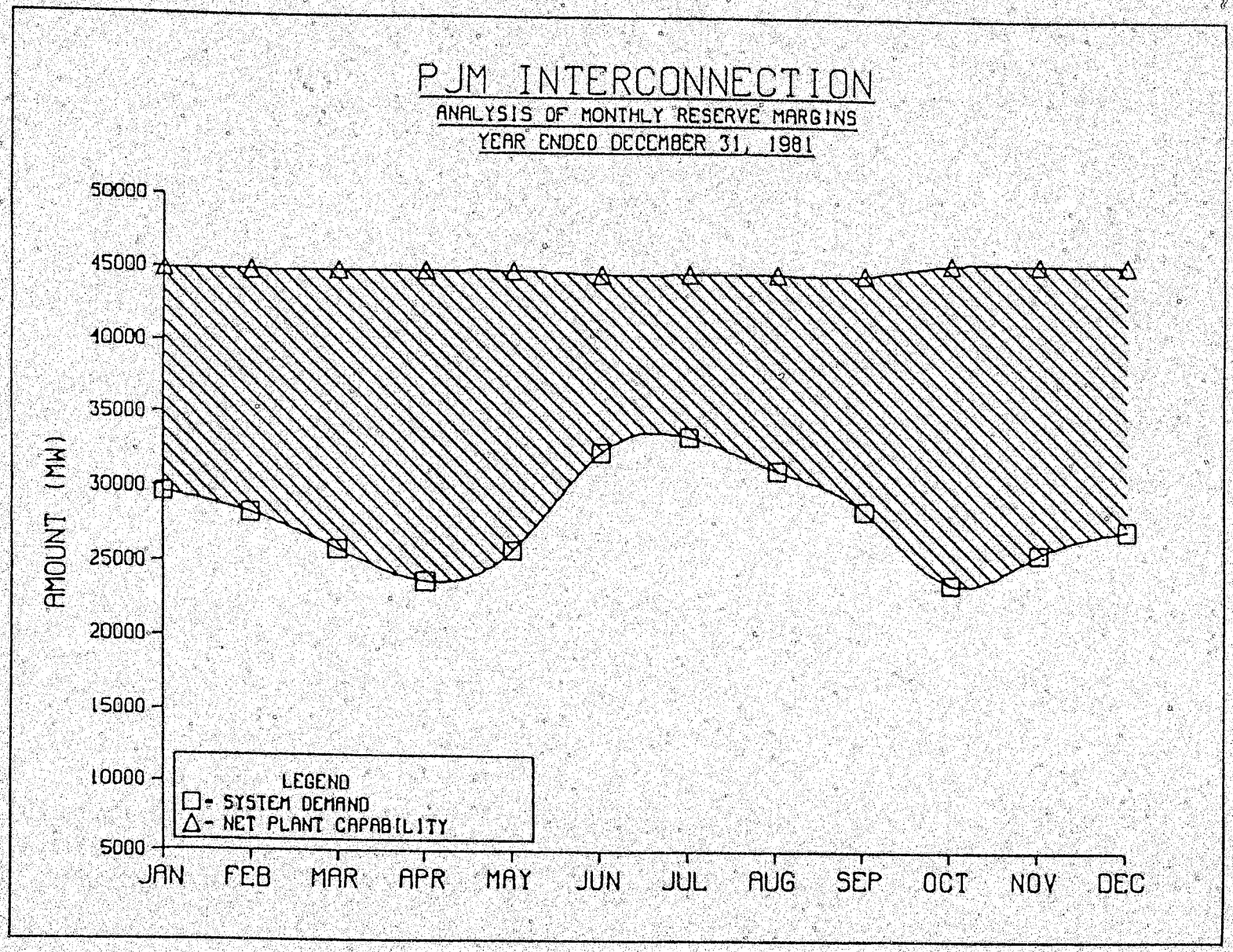
PJM INTERCONNECTION

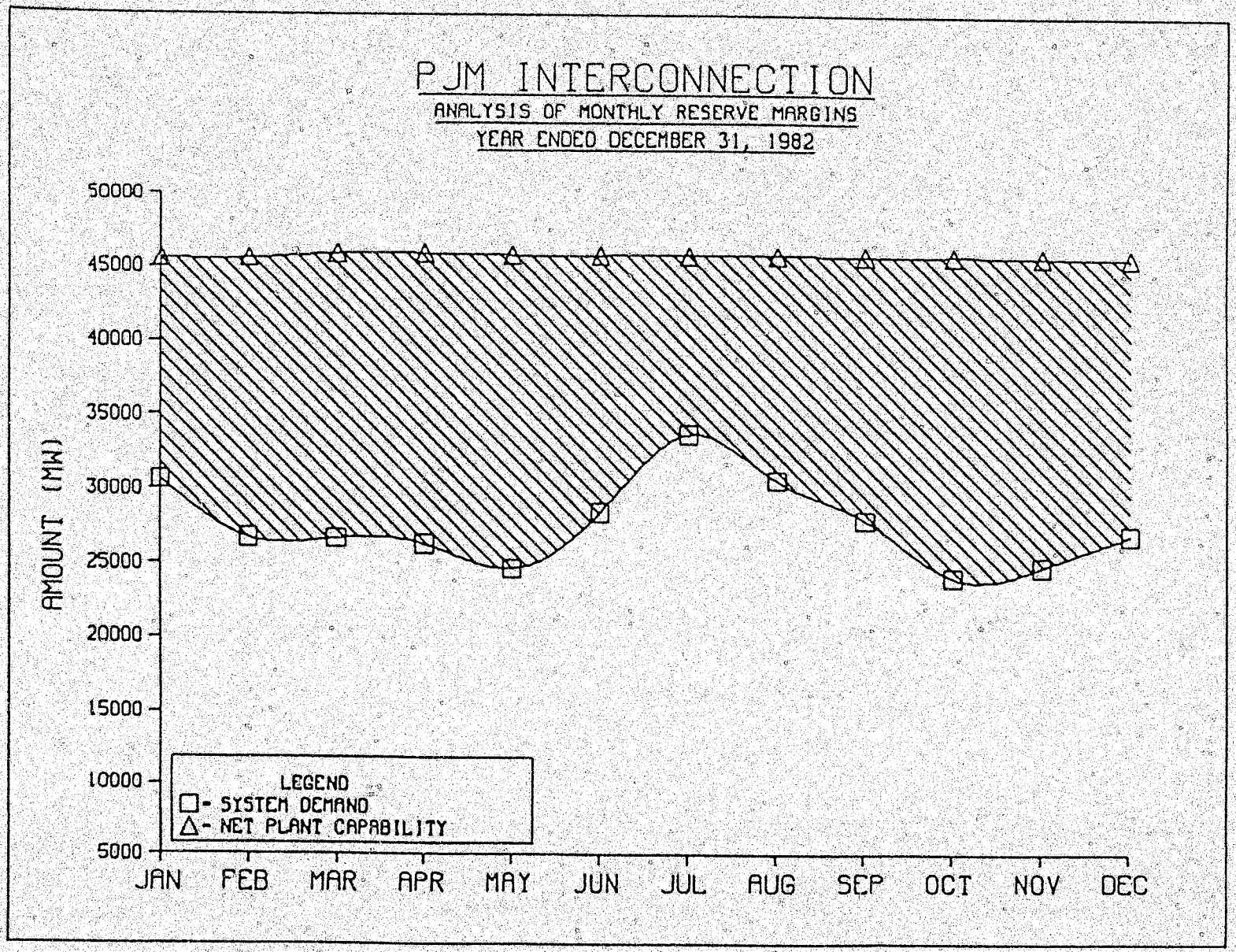
ANALYSIS OF MONTHLY RESERVE MARGINS

YEAR ENDED DECEMBER 31, 1979

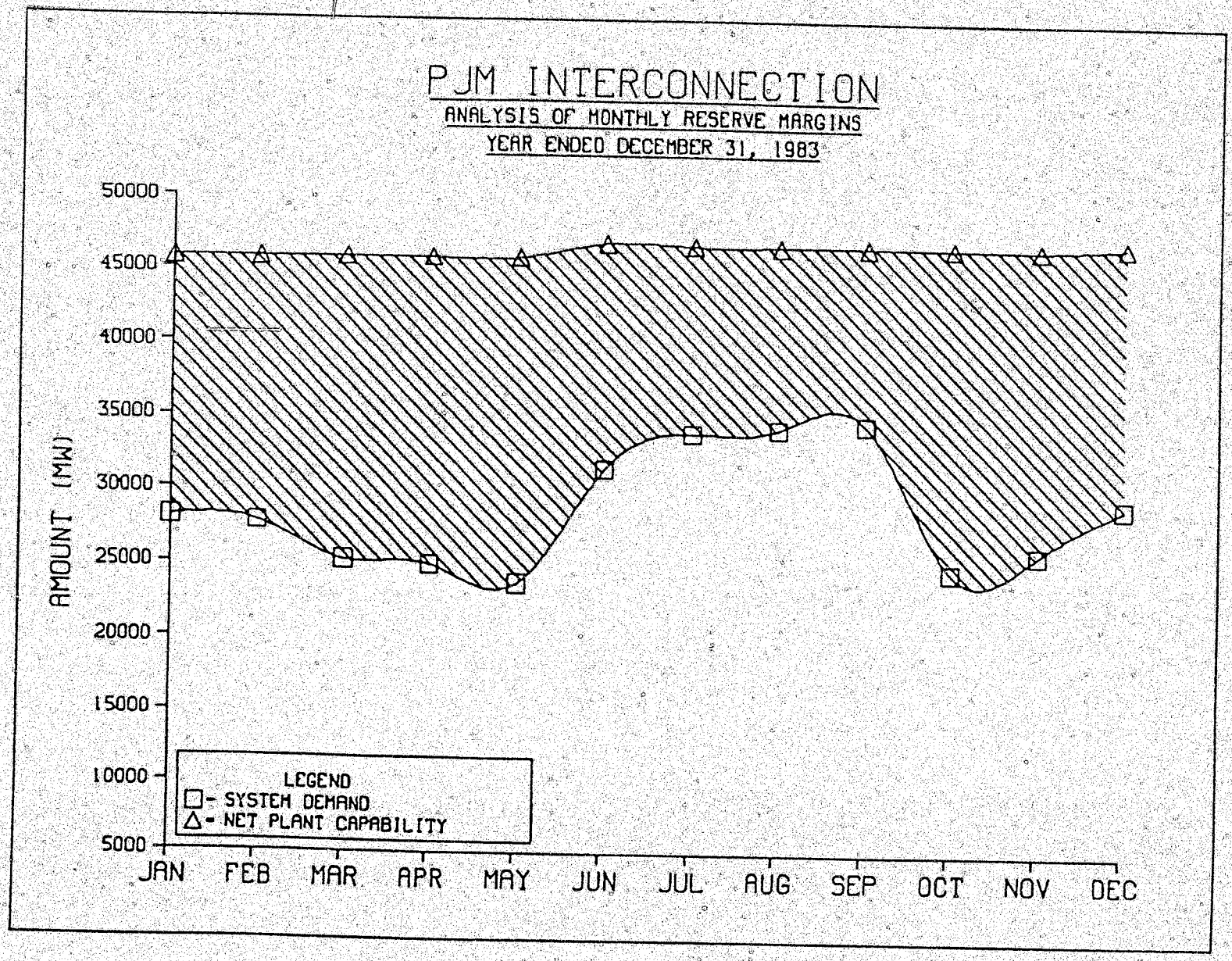



PJM INTERCONNECTION
ANALYSIS OF MONTHLY RESERVE MARGINS
YEAR ENDED DECEMBER 31, 1980
AMOUNT (MW)
50000
45000
40000
35000
30000
25000
20000
15000
10000
5000
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
LEGEND
□ - SYSTEM DEMAND
△ - NET PLANT CAPABILITY


PJM INTERCONNECTION
ANALYSIS OF MONTHLY RESERVE MARGINS
YEAR ENDED DECEMBER 31, 1981
AMOUNT (MW)
50000
45000
40000
35000
30000
25000
20000
15000
10000
5000
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
LEGEND
□- SYSTEM DEMAND
△- NET PLANT CAPABILITY



Appendix B
Chart 19

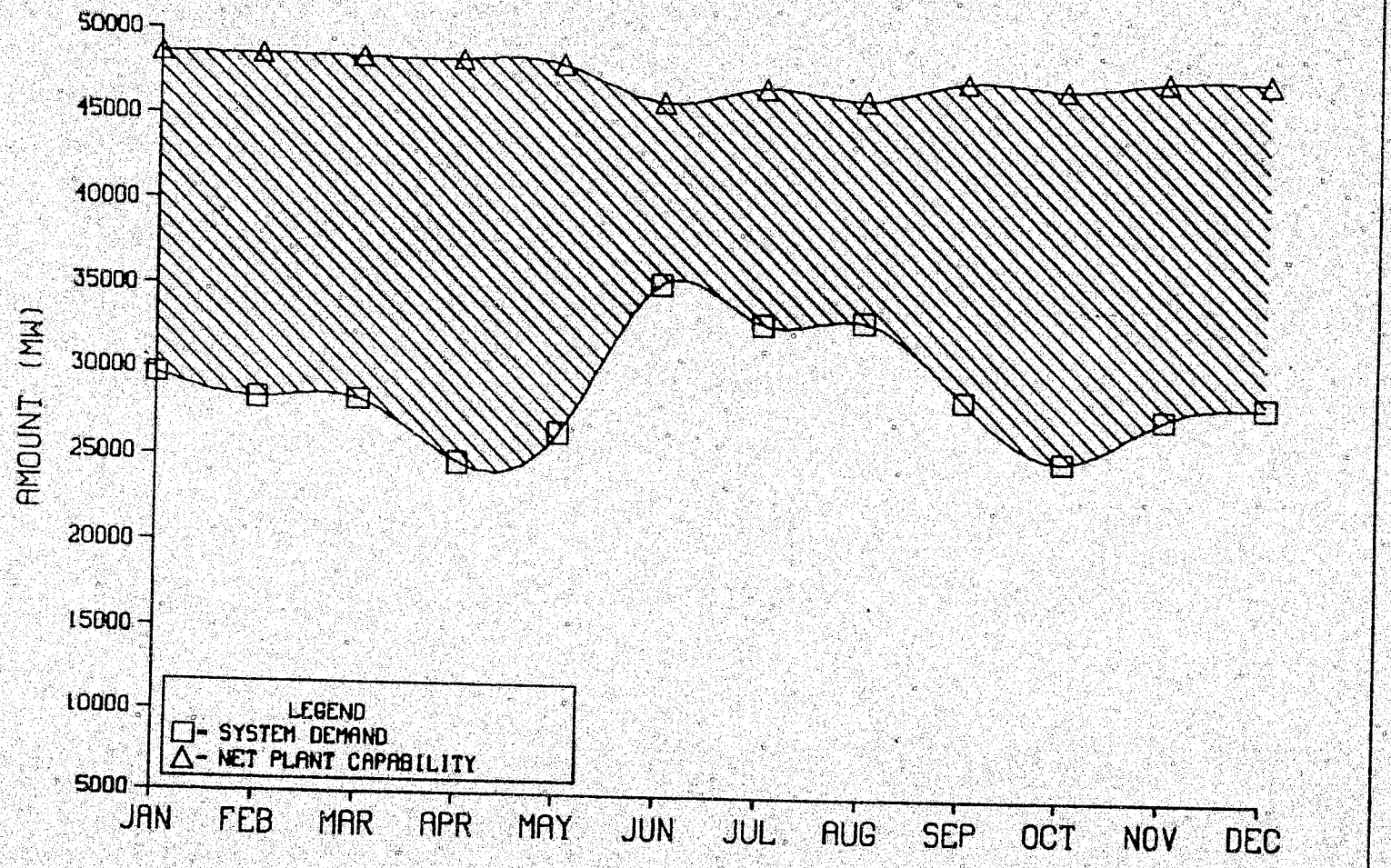


Appendix B
Chart 20

PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS

YEAR ENDED DECEMBER 31, 1984



Appendix B
Chart 21

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1979
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,698	44,660	44,643	44,613	44,613	44,613	44,613	44,613	44,613	44,623	44,631	44,631
Scheduled Maintenance (MW)	3,516	4,689	6,547	7,311	5,991	2,938	1,182	1,459	1,118	4,547	4,110	4,069
Adjusted Capability (MW)	41,182	39,971	38,096	37,302	38,622	41,675	43,431	43,154	43,495	40,076	40,521	40,562
System Demand (MW)	28,171	28,529	25,883	24,634	25,955	26,730	30,371	31,654	29,957	23,970	25,385	27,732
Capacity Margin (MW)	13,011	11,442	12,213	12,668	12,667	14,945	13,060	11,500	13,538	16,106	15,136	12,830
Capacity Margin as a Percent of System Demand	46.2%	40.1%	47.2%	51.4%	48.8%	55.9%	43.0%	36.3%	45.2%	67.2%	59.6%	46.3%

e: Form 12-E-2 Reports.

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PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1980
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,492	44,499	44,498	44,496	44,496	44,715	44,752	44,753	44,753	44,994	44,994	44,994
Scheduled Maintenance (MW)	5,863	5,414	5,686	5,978	7,710	3,049	1,729	1,674	2,043	8,529	7,147	5,414
Adjusted Capability (MW)	38,629	39,085	38,812	38,518	36,786	41,666	43,023	43,079	42,710	36,465	37,847	39,580
System Demand (MW)	27,621	27,967	27,100	23,243	24,130	29,153	34,420	33,247	33,972	23,533	26,072	27,448
Capacity Margin (MW)	11,008	11,118	11,712	15,275	12,656	12,513	8,603	9,832	8,738	12,932	11,775	12,132
Capacity Margin as a Percent of System Demand	39.9%	39.8%	43.2%	65.7%	52.4%	42.9%	25.0%	29.6%	25.7%	55.0%	45.2%	44.2%

e: Form 12-E-2 Reports.

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Schedule 3
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PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1981
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	44,900	44,870	44,828	44,840	44,840	44,625	44,627	44,627	44,627	45,393	45,393	45,393
Scheduled Maintenance (MW)	3,871	4,308	7,834	6,268	8,307	3,931	1,710	1,908	4,147	5,704	5,172	4,546
Adjusted Capability (MW)	41,029	40,562	36,994	38,572	36,533	40,694	42,917	42,719	40,480	39,689	40,221	40,847
System Demand (MW)	29,625	28,313	25,870	23,715	25,853	32,448	33,528	31,292	28,608	23,680	25,735	27,393
Capacity Margin (MW)	11,404	12,249	11,124	14,857	10,680	8,246	9,389	11,427	11,872	16,009	14,486	13,454
Capacity Margin as a Percent of System Demand	38.5%	43.3%	43.0%	62.6%	41.3%	25.4%	28.0%	36.5%	41.5%	67.6%	56.3%	49.1%

ce: ERA Form 119-M.

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1982
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	45,570	45,547	45,859	45,859	45,781	45,781	45,796	45,796	45,772	45,783	45,774	45,774
Scheduled Maintenance (MW)	3,415	4,307	6,355	8,439	7,465	4,636	1,388	3,135	3,057	8,308	6,123	6,184
Adjusted Capability (MW)	42,155	41,240	39,504	37,420	38,316	41,145	44,408	42,661	42,715	37,475	39,651	39,590
System Demand (MW)	30,621	26,734	26,683	26,302	24,685	28,469	33,741	30,668	28,042	24,147	24,883	27,062
Capacity Margin (MW)	11,534	14,506	12,821	11,118	13,631	12,676	10,667	11,993	14,673	13,328	14,768	12,528
Capacity Margin as a Percent of System Demand	37.7%	54.3%	48.0%	42.3%	55.2%	44.5%	31.6%	39.1%	52.3%	55.2%	59.3%	46.3%

ce: ERA Form 119-M.

PJM INTERCONNECTION

Analysis of System Capacity and Demand for the Year 1983
with Adjustments for Scheduled Maintenance

Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
Net Plant Capability (MW)	45,794	45,794	45,802	45,814	45,814	46,864	46,712	46,704	46,704	46,734	46,734	47,056
Scheduled Maintenance (MW)	6,355	6,277	7,412	9,156	9,456	7,032	4,343	3,215	3,914	8,616	6,279	5,022
Adjusted Capability (MW)	39,439	39,517	38,390	36,658	36,358	39,832	42,369	43,489	42,790	38,118	40,455	42,034
System Demand (MW)	28,092	27,813	25,278	24,994	23,786	31,520	34,021	34,346	34,678	24,742	25,922	29,241
Capacity Margin (MW)	11,347	11,704	13,112	11,664	12,572	8,312	8,348	9,143	8,112	13,376	14,533	12,793
Capacity Margin as a Percent of System Demand	40.4%	42.1%	51.9%	46.7%	52.9%	26.4%	24.5%	26.6%	23.4%	54.1%	56.1%	43.8%

ce: IR-PAIEUG-1-3.

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PJM INTERCONNECTION

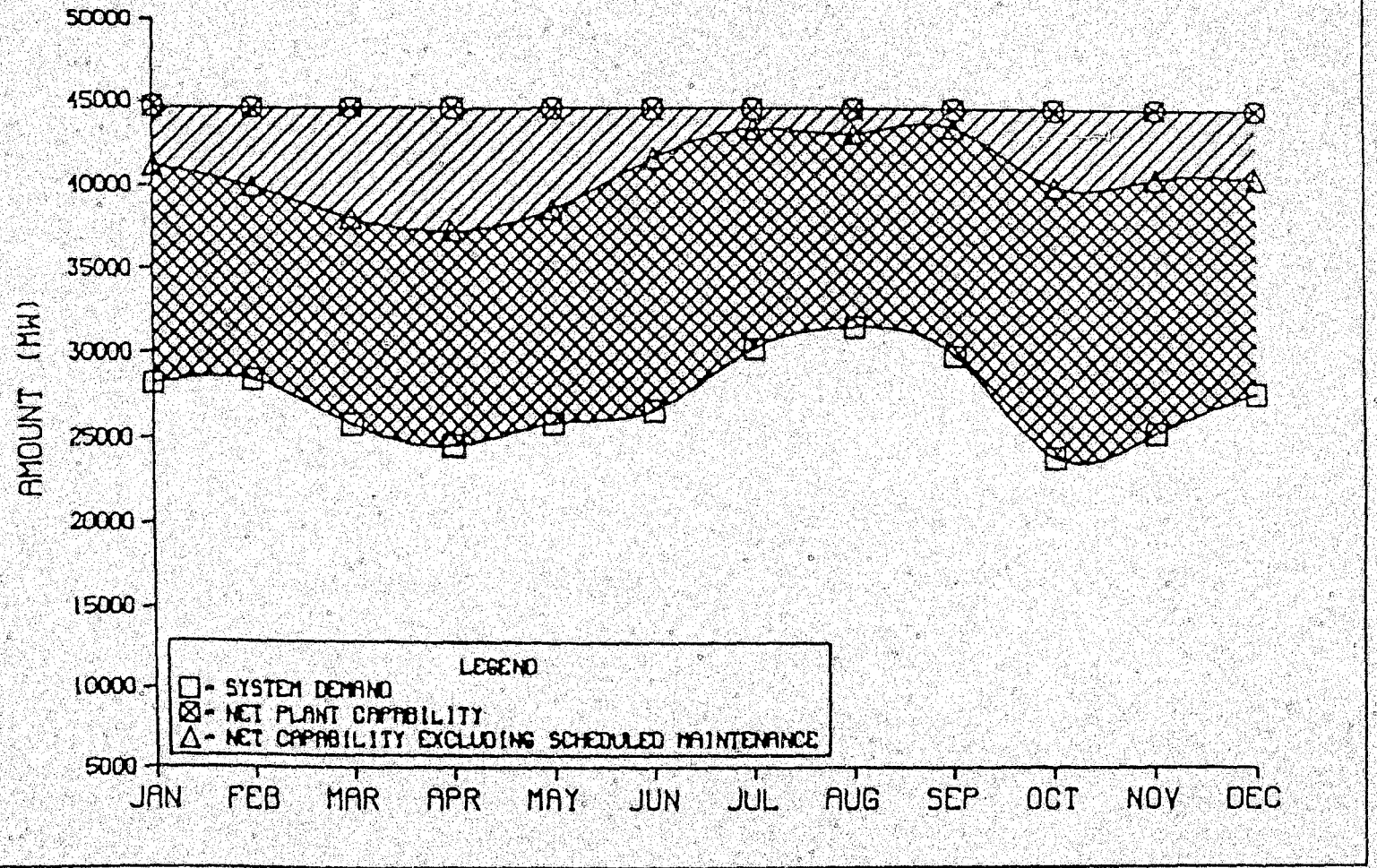
Analysis of System Capacity and Demand for the Year 1984
with Adjustments for Scheduled Maintenance

Line	Description	Jan (1)	Feb (2)	Mar (3)	Apr (4)	May (5)	Jun (6)	Jul (7)	Aug (8)	Sep (9)	Oct (10)	Nov (11)	Dec (12)
1	Net Plant Capability (MW)	48,604	48,509	48,367	48,285	48,057	45,899	46,833	46,190	47,371	47,034	47,639	47,652
2	Scheduled Maintenance (MW)	6,065	6,281	6,541	7,010	9,239	7,698	4,073	4,424	6,467	9,370	10,108	7,766
3	Adjusted Capability (MW)	42,539	42,228	41,826	41,275	38,818	38,201	42,760	41,766	40,904	37,664	37,531	39,886
4	System Demand (MW)	29,658	28,332	28,261	24,704	26,486	35,319	33,013	33,229	28,694	25,239	27,786	28,539
5	Capacity Margin (MW)	12,881	13,896	13,565	16,571	12,332	2,882	9,747	8,537	12,210	12,425	9,745	11,347
6	Capacity Margin as a Percent of System Demand	43.4%	49.0%	48.0%	67.1%	47.0%	8.2%	30.0%	26.0%	43.0%	49.2%	35.1%	40.0%

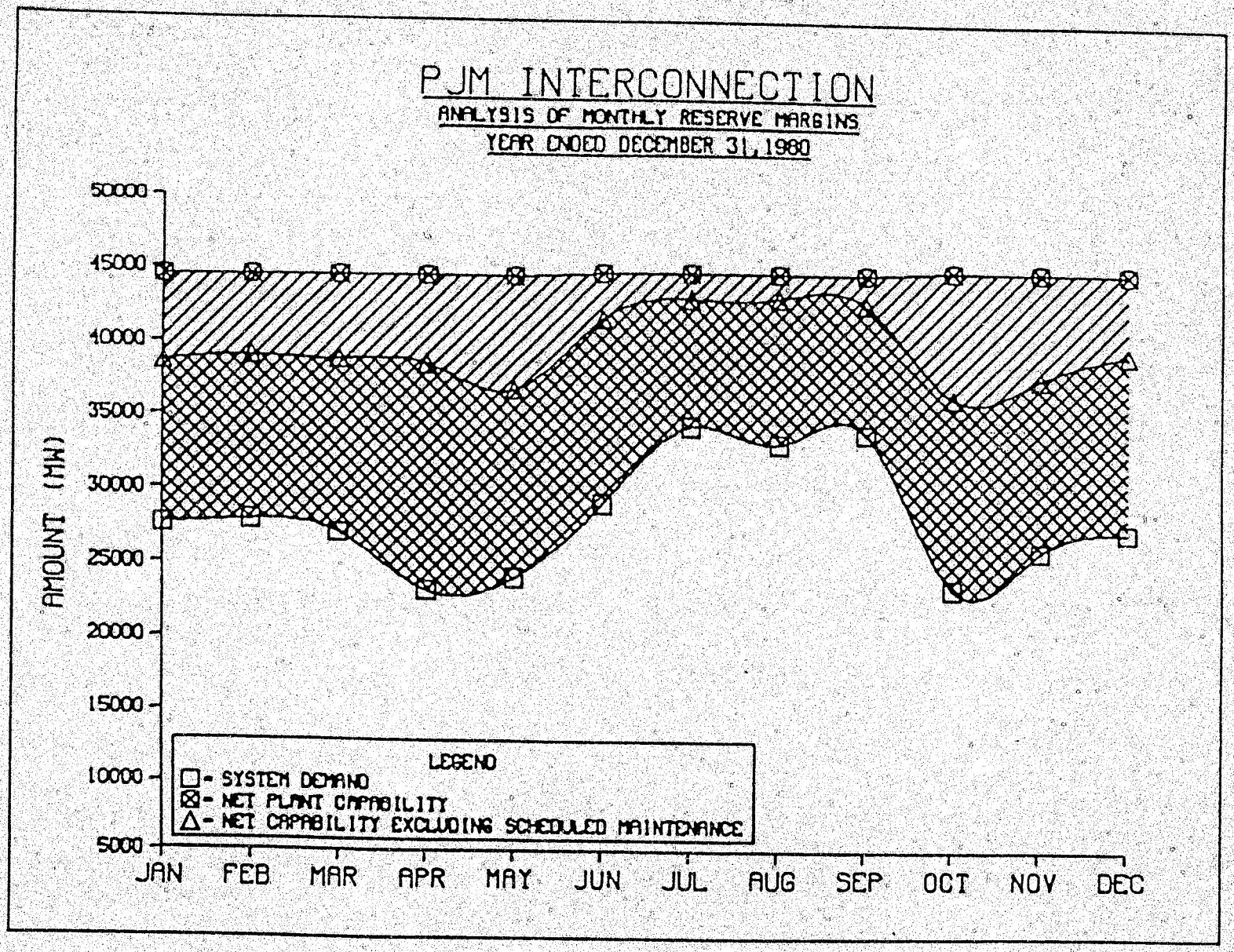
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PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS
YEAR ENDED DECEMBER 31, 1979



Appendix B
Chart 22

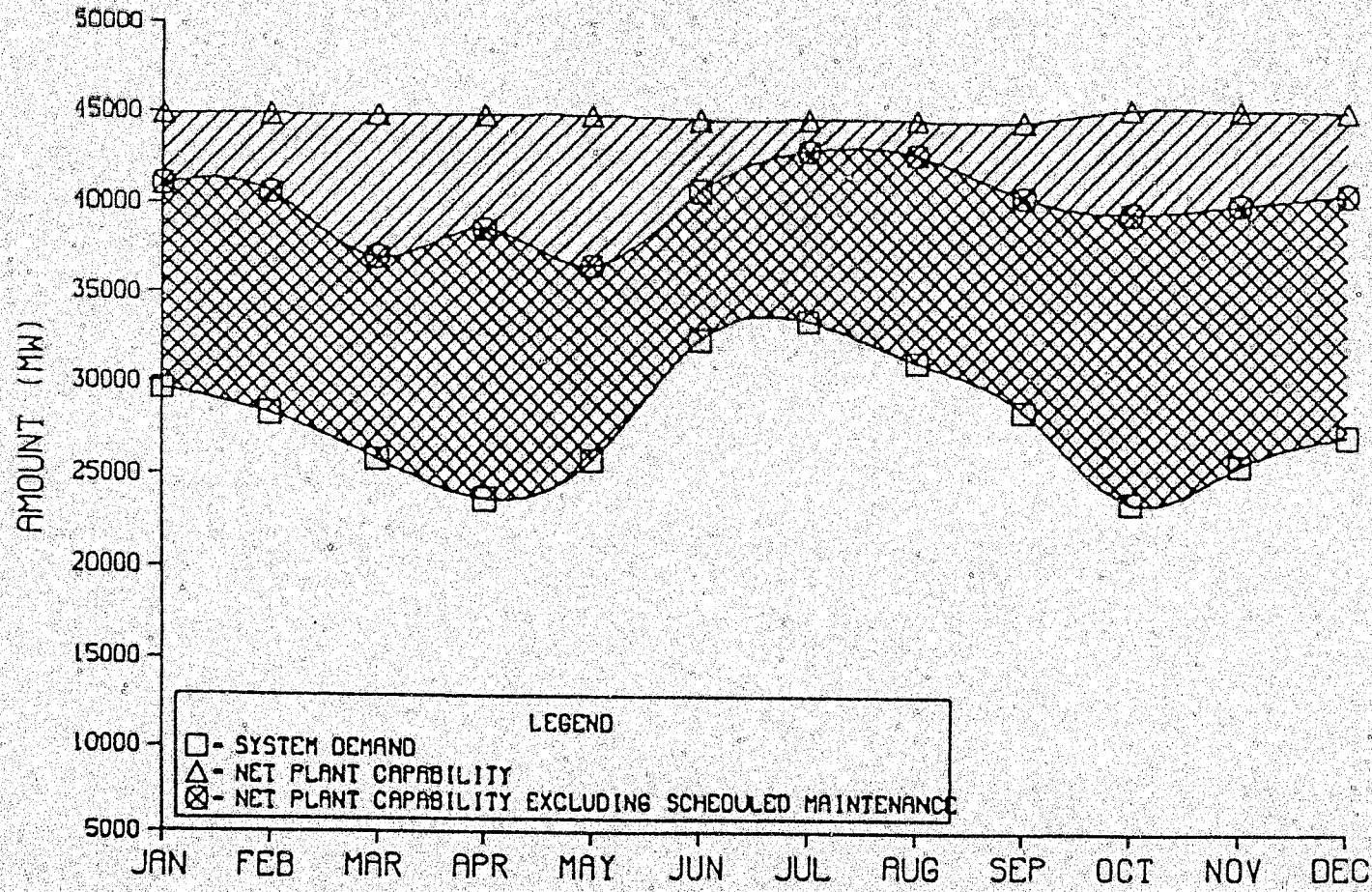


Appendix B
Chart 23

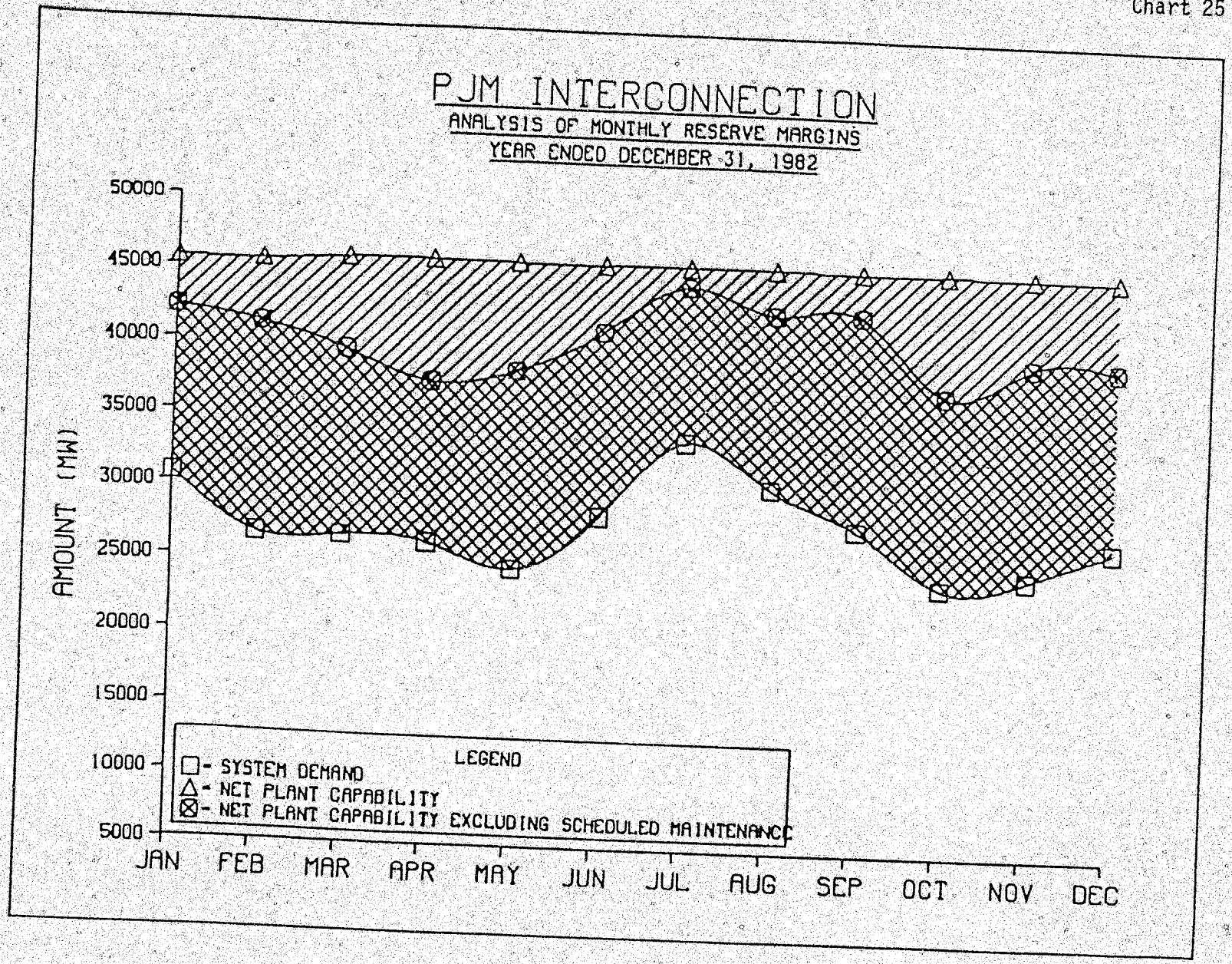
PJM INTERCONNECTION

ANALYSIS OF MONTHLY RESERVE MARGINS

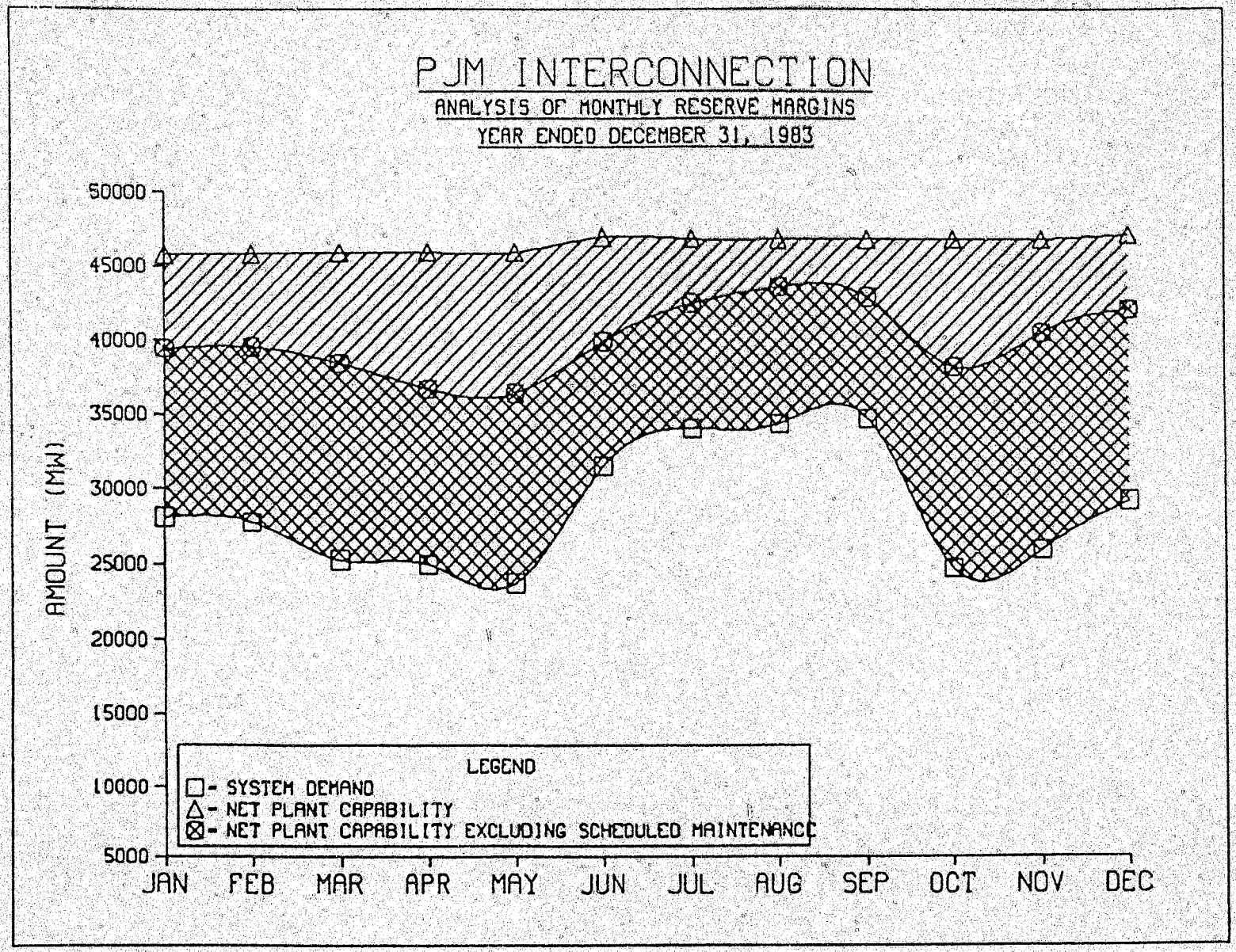
YEAR ENDED DECEMBER 31, 1981



Appendix B
Chart 24



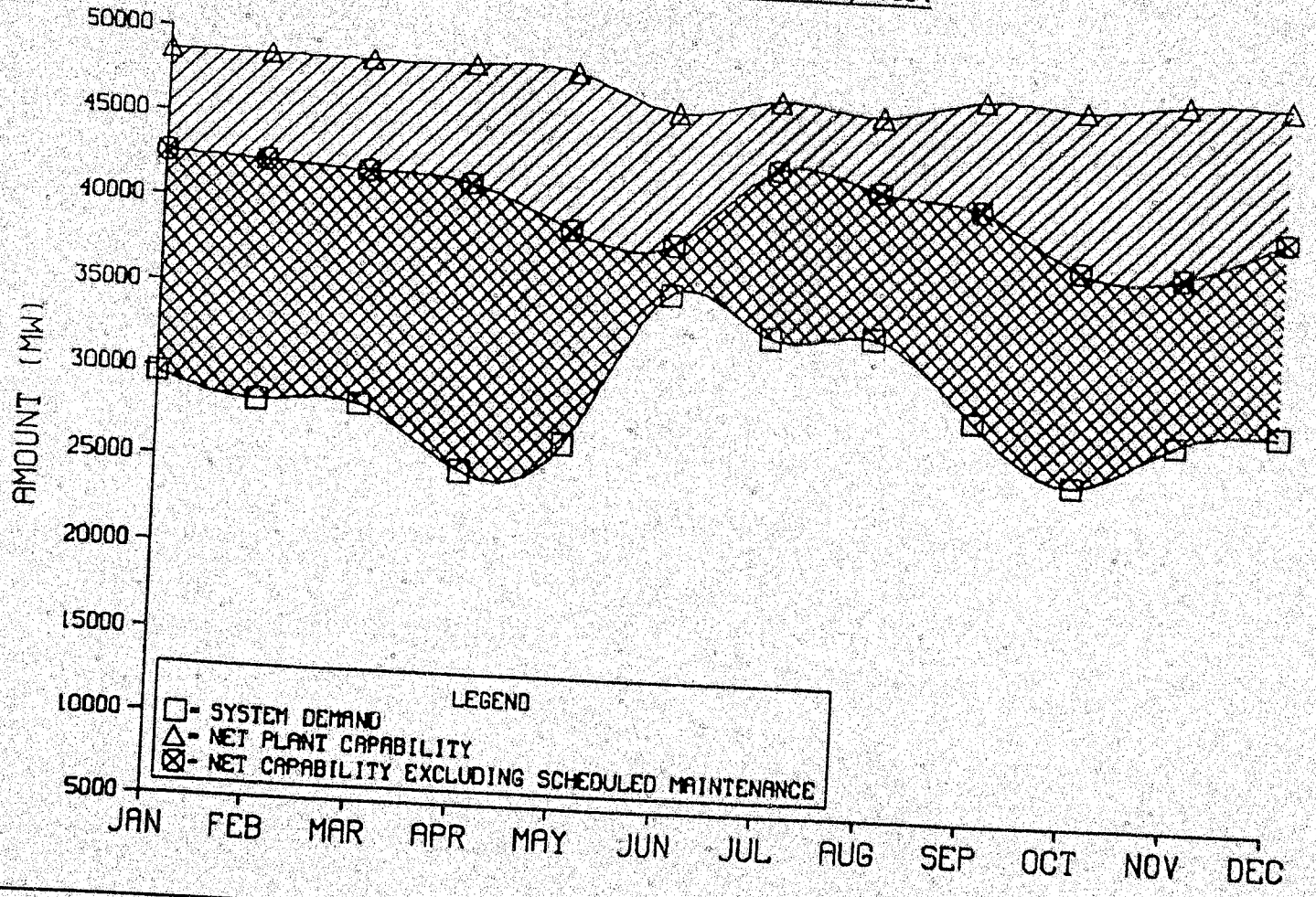
Appendix B
Chart 25


PJM INTERCONNECTION
ANALYSIS OF MONTHLY RESERVE MARGINS
YEAR ENDED DECEMBER 31, 1983
AMOUNT (MW)
50000
45000
40000
35000
30000
25000
20000
15000
10000
5000
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
LEGEND
□- SYSTEM DEMAND
△- NET PLANT CAPABILITY
⊠- NET PLANT CAPABILITY EXCLUDING SCHEDULED MAINTENANCE

PJM INTERCONNECTION

ANALYSIS OF MONTHLY CAPACITY MARGINS

YEAR ENDED DECEMBER 31, 1984



Appendix B
Chart 27

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Testimony and Exhibit

of

JEFFRY POLLOCK

On behalf of the

Philadelphia Area Industrial Energy User Group

(Allied Corporation, Fibers Division
Boeing Vertol Company
B Proli, Inc.
The Budd Company
Liquid Air Corporation of North America
Lukens Steel Company
Nabisco Brands, Inc.
SDC (a Burroughs Company)
SmithKline Beckman Corporation
Sun Refining and Marketing Company
3M Company)

and

United States Steel Corporation

January 1986
Project 4035

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

Before the

Pennsylvania Public Utility Commission

Docket No. R-850152

PHILADELPHIA ELECTRIC COMPANY

Direct Testimony

of

JEFFRY POLLOCK

On behalf of the

Philadelphia Area Industrial Energy Users Group

Allied Corporation, Fibers Division

Boeing Vertol Company

Budd Co., Inc.

The Budd Company

FMC Corporation of North America

Lukens Steel Company

Nabisco Brands, Inc.

Sperry (a Burroughs Company)

Smithkline Beckman Corporation

Sun Refining and Marketing Company

3M Company)

and

United States Steel Corporation

January 1986

Project 4035

Brubaker & Associates, Inc.

St. Louis, Missouri 63141-0110

PHILADELPHIA ELECTRIC COMPANY

before the

Pennsylvania Public Utility Commission

Docket No. R-850152

Summary of the
Recommendations of Jeffry Pollock

This testimony is being sponsored on behalf of the Philadelphia Area Industrial Energy Users Group (PAIEUG) and U. S. Steel Corporation, and it addresses rate spread and rate design issues. The following is a summary of the specific recommendations:

(1) The four coincident peak (4CP) cost-of-service study filed by Philadelphia Electric Company (PECO) in this Docket (Schedule 1, Page 1) is unacceptable and should be rejected for the reasons cited by my colleague, Dr. Bloom. Specifically:

(a) The weather-sensitive load was significantly understated; and

(b) The Rate HT loads were overstated because the demands related to supplemental energy service and curtailable service were erroneously included in the derivation of the production demand allocation factor (A-1), the same as firm Rate HT demands. This is despite the fact that PECO does not have the same obligation to provide continuous, uninterrupted service. In other words, supplemental and curtailable service is of a lower quality and does not require PECO to construct generation capacity because this service can be curtailed when capacity is unavailable and needed to maintain service to PECO's firm customers.

(2) The adjustments proposed by Dr. Bloom to PECO's 4CP cost-of-service study should be adopted. This study (Schedule 1, Page 2) is a more acceptable basis for determining rate spread and rate design at least for the first year of a phase-in, if adopted by the Commission. Further, the results are more consistent with prior cost studies (Schedule 2).

(3) If a phase-in is adopted, then rate spread issues should be continually reviewed to assure that the rates approved in this Docket would continue to adhere to cost of service. In other words, the phase-in should not provide for automatic recovery because it would maintain (or possibly worsen) the revenue/cost relationships, particularly if conditions that affect the cost-of-service study (e.g., weather) were different than during the test year.

(4) Irrespective of which cost-of-service study is determined to be acceptable, the modified zero fuel method--which has been approved by the Commission in the last three PECO rate cases--should be used to distribute the nonfuel portion of any rate increase approved by the Commission, subject to two constraints:

(a) The relative rate of return of any major customer class should not exceed 140% of the system average rate of return.

(b) The revenue subsidies at approved rates should be no higher than, and preferably less than, the corresponding revenue subsidies at present rates (Schedules 3 through 6).

PECO's rate spread should be categorically rejected because: (1) nonjurisdictional classes would be subsidized by retail classes and (2) some retail classes (e.g., street lighting, SEPTA and AMTRAK) would receive more favorable treatment than others.

(5) The design of Rate HT should be modified (relative to PECO's proposal) as follows:

(a) Most of the increase assigned to Rate HT should be recovered in the capacity charge resulting in a much higher percent increase

than in the energy charges. The demand cost recovered in the tail block energy charge should not be increased. At most, the percent increase in the tail block energy charge should not exceed the percent increase in the first and second block energy charges, when measured relative to the present charges excluding embedded fuel costs (Schedules 7 and 8).

(b) The high voltage discount should be modified to include an explicit recognition of the lower cost to provide service to those Rate HT customers who take service at 66,000 volts and above. This lower cost of service is due to the lower demand and energy losses incurred to provide service at these voltages. Because the present discount only reflects the transformation cost avoided by PECO and not the avoided demand and energy losses, these higher voltage customers should receive an additional discount of at least 1% of the capacity and base energy charges.

(c) The Rate HT Curtailment Rider should not be diminished in value (which would be the result of PECO's proposal to maintain the credit at $2.00 per kW). Instead, the credit should be increased to at least $3.40 (and possibly as high as $3.80) in order to maintain the same relationship in the cost of providing curtailable versus firm electric service. By increasing the credit, the Curtailment HT Rider would be more attractive and provide a more suitable alternative to the Supplemental Energy Rider for those customers who determine that a lower quality of service is both cost-effective, as well as cost-competitive (Schedules 9 and 10).

(6) PECO should be ordered to develop certain cost-of-service and rate design data by delivery voltage within the High Tension class in its next rate case. This should include:

(a) Coincident and noncoincident peak demands.

(b) Energy sales, billing demand and demand subject to the high voltage discount.

(c) The transformation and other distribution costs avoided at higher delivery voltages.

(d) Differences in demand and energy losses.

PHILADELPHIA ELECTRIC COMPANY

before the

Pennsylvania Public Utility Commission

Docket No. R-850152

Testimony of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock, 605 Old Ballas Road, St. Louis, Missouri.

Q WOULD YOU PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE?

A This is set forth in Appendix A to the testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Philadelphia Area Industrial Energy Users Group (PAIEUG) and U. S. Steel Corporation, all of whom are customers of Philadelphia Electric Company (PECO). These companies use substantial amounts of electricity primarily for manufacturing, and they purchase electric service on Rate HT.

Q WHAT ISSUES DO YOU ADDRESS?

A I am testifying on the method of spreading the nonfuel rate increase among the various rate schedules (rate spread) and the design of Rate HT.

A summary of the specific recommendations is incorporated

prior to the main body of testimony.

Q IS DR. MELVIN P. BLOOM ALSO APPEARING ON BEHALF OF THE SAME INTERVENORS LISTED ABOVE?

A Yes. Dr. Bloom is testifying on cost-of-service and rate design issues including:

(1) PECO's 4CP cost-of-service study and, in particular, the derivation of the various demand allocation factors,

(2) The problems with using the Bary curve for rate design, and

(3) The load characteristics of PECO and the load and supply characteristics reserve of the PJM interconnected system.

Q DOES YOUR TESTIMONY ADDRESS REVENUE REQUIREMENT ISSUES?

A No. However, I have used PECO's claimed rate base, rate of return and operating expenses for the test year ending June 30, 1986 so that our presentation would be consistent with the revenue levels proposed by PECO. The use of this information should not be considered as an endorsement of PECO's claimed revenue requirement.

Q HAVE YOU PREPARED ANY EXHIBITS FOR SUBMISSION?

A Yes. I am sponsoring Exhibit JP-1 ( ), consisting of ten schedules.

THE RESULTS OF PECO'S 4CP COST-OF-SERVICE STUDY ARE ERRONEOUS AND, THEREFORE, IT SHOULD NOT BE USED TO DETERMINE THE RATE SPREAD AND RATE DESIGN

Q MR. SUNDERMEIR, ON BEHALF OF PECO, HAS TESTIFIED THAT THE COST OF

SERVICE STUDY PRESENTED IN EXHIBIT WFS-1 UTILIZES ESSENTIALLY THE SAME ALLOCATION TECHNIQUES THAT HAVE BEEN USED IN PRIOR PECO RATE CASES. DO YOU CONCUR?

A Yes. Except for the treatment of the SEPTA and AMTRAK loads as separate customer classes (rather than combined with the high tension class as in the past), the cost-of-service study presented in this Docket is essentially the same as the studies presented by PECO in prior rate cases.

Q ARE THE RESULTS OF PECO'S 4CP COST-OF-SERVICE STUDY IN THIS DOCKET ACCEPTABLE FOR USE IN DETERMINING RATE SPREAD AND RATE DESIGN ISSUES?

A No, they are not. Although PECO has employed the same allocation techniques as in the past, the results should not be used to determine rate spread and rate design in this Docket because, based on Dr. Bloom's analysis, the various demand allocation factors are erroneous. Specifically, Dr. Bloom has identified two problems with the demand allocation factors.

First, the weather-sensitive demands were signficantly understated relative to past cost-of-service studies. This occurred because the summer of 1984--which was used as the starting point for developing the test year demand allocation factors--was significantly cooler than normal as measured by the effective degree hours (EDH) in each of the four summer peak months. I have reviewed Dr. Bloom's analysis and concur with his findings with respect to the

abnormal 1984 summer weather conditions.

Q WHAT WAS THE SECOND PROBLEM WITH THE 4CP DEMAND ALLOCATION FACTORS?

A In deriving the demand allocation factors, PECO used the total coincident demand of each Rate HT customer, irrespective of the quality of service provided. This is an important distinction for the high tension class because not all service is provided on a firm basis. A significant portion of service is provided on a curtailable basis either from the HT Curtailment Rider or the Supplemental Energy provision of the Night Service HT Rider.

Q WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN THE QUALITY OF SERVICE IN DEVELOPING THE DEMAND ALLOCATION FACTORS?

A If the lower quality of service provided to the curtailment and supplemental energy customers is not recognized for costing purposes, but is reflected in the determination of that class's revenues, then the inevitable result would be to understate the class's rate of return. This occurs because, for costing purposes, the demands are assumed to be firm while, for revenue purposes, not all of the demand is priced at the firm rate. Because curtailment and supplemental energy service is priced below the corresponding price for firm service (in recognition of the lower quality of service), the revenues are below the level which they would otherwise be if the entire class received firm electric service.

In summary, there is a fundamental mismatch between costing

and pricing for the high tension class. In this instance, the high tension class cost of service is overstated relative to the price which high tension customers pay. Although the price reflects the different quality of service provided to the high tension class, the costs allocated to this class do not.

Q HOW SHOULD THIS MISMATCH BE RESOLVED?

A An appropriate resolution would be to completely remove that portion of the high tension class's coincident demand related to curtailment or supplemental energy service. This treatment is appropriate because PECO does not have the same obligation to provide continuous service to curtailment and supplemental energy customers as it has in the case of all other firm customers.

For example, according to the tariff (Electric-Pa. PUC No.26, Page No. 61), supplemental energy "must be completely interruptible on notice of at least one-half hour when, in the sole judgment of the Company, any capacity limitations exist." Based on PECO's response to IR-PAIEUG-1-12, the phrase "capacity limitations" means whenever PECO is required to utilize maximum emergency generation. In other words, when the supply of electricity is limited relative to the demand, the Company will require interruptions. The same provision also applies for curtailment service.

Stated differently, if the capacity which is presently being used by curtailment and supplemental energy customers is required in order to continue service to the utility's firm customers, the

former load can be removed from the system. Thus, PECO does not have the same obligation to provide a continuous supply of power to its curtailment and supplemental energy customers as it has to its firm customers. This being the case, there is no production demand-related cost associated with, or allocable to, curtailment and supplemental energy service.

Q WOULD THIS STILL BE THE CASE EVEN THOUGH, ACCORDING TO ITS OWN PROJECTIONS, PECO WILL EXPERIENCE RESERVE MARGINS IN EXCESS OF ITS PLANNING RESERVE MARGIN?

A Yes. Even assuming that the amount of installed capacity were more than adequate to serve the load at all times, the presence of curtailment and supplemental energy load provides a hedge against: (1) the possibility that sufficient generating capacity may, at times, be unavailable due to a forced or scheduled outage or because the utility has elected not to have this capacity in an operating status; and (2) the uncertainties surrounding the load forecasts--that is, tomorrow's load is never known with certainty. Further, because this capacity can be utilized to provide curtailment and supplemental energy service to the extent that it is not required to maintain firm service, the utility is able to defray more of the fixed costs than would otherwise be the case if this service were not provided.

Thus, curtailment and supplemental energy loads provide two important benefits to all ratepayers. First, in the long run, this

service could offset some of the cost of providing reserve generating capacity requirements, thereby reducing total capacity costs from what they would otherwise be without the presence of curtailment and supplemental energy service. Second, this service helps to defray some of the fixed costs and, therefore, reduces the cost to serve the remaining firm customers.

Q HAVE YOU REVIEWED THE SPECIFIC ADJUSTMENT RECOMMENDED BY DR. BLOOM TO REMOVE THE CURTAILMENT AND SUPPLEMENTAL ENERGY DEMANDS FROM THE HIGH TENSION CLASS COINCIDENT PEAK DEMANDS?

A Yes, I have. I concur with Dr. Bloom's adjustments. (It should be noted that, because the supplemental energy revenues were not reflected in the cost-of-service study, the high tension class rate of return is understated even though the curtailable demands were removed.)

THE PAIEUG ET AL REVISED 4CP COST-OF-SERVICE STUDY SHOULD BE USED TO DETERMINE THE RATE SPREAD AND RATE DESIGN IN THIS DOCKET

Q DO THE TWO ADJUSTMENTS RECOMMENDED BY DR. BLOOM TO THE DEMAND ALLOCATION FACTORS HAVE A SIGNIFICANT IMPACT ON THE COST-OF-SERVICE STUDY RESULTS BASED ON THE 4CP METHOD?

A Yes, they do. Exhibit JP-1 ( ), Schedule 1, is a summary of the cost-of-service study results. Page 1 is based on PECO's cost study, while Page 2 is based on one of the revised cost studies that Dr. Bloom is sponsoring. In this particular study, the weather-sensitive demands were reflective of the EDH's during the

four summer peak days in 1985. As Dr. Bloom demonstrates in his Exhibit MPB-3 ( ), this revised study yields the lowest rate of return for the high tension class relative to the other weather-adjusted cost studies.

For example, under the PAIEUG et al revised 4CP cost-of-service study, the high tension class is equal to the system average rate of return at present rates. Under PECO's cost study, by comparison, this class would have a below-average rate of return. This translates into about a $50 million differential in the high tension class revenue requirements at present rates.

The results are also significantly different for the primary and residential classes. Under the revised study, the primary class rate of return is above the system average at present rates, while under PECO's cost study, it is close to, but below, the system average. Similarly, the residential class rate of return is below (rather than equal to) the system average based on this class's coincident demands which are reflective of more normal summer peak day weather conditions.

As further evidence that Dr. Bloom's adjustments to the demand allocation factors are appropriate, Exhibit JP-1 ( ), Schedule 2, demonstrates that the results of the PAIEUG et al cost study are much more consistent with prior PECO 4CP cost-of-service studies than the current PECO cost study. This consistency is illustrated below:

Comparison of 4CP Cost-of-Service Study Results Between Last Case and This Case Based on PAIEUG et al's Adjustments

Rate Class	Index of Return		
		This Case	
	Last Case*	PAIEUG et al	PECO
High Tension**	116	100	84
Primary	140	117	97
Secondary	140	126	126
Residential	71	84	100
Street Lighting	90	198	197

*PECO proposed rates
**Includes SEPTA and AMTRAK

Further, under PECO's proposed rate spread, the interclass subsidies would be much more substantial based on the revised (1985 EDH) cost study. For example, under the revised study, the high tension class would be providing a $55.7 million subsidy at proposed rates. By contrast, PECO's cost study shows that this class would be subsidized by about $24.7 million. Thus, the results differ by nearly $80 million at proposed rates for the high tension class. There are also significant differences between these two cost studies for other classes as well (e.g., primary, $22 million; residential, $94 million, et cetera).

Q WHAT IMPLICATIONS DO YOUR FINDINGS HAVE RELATIVE TO PECO'S PROPOSED PHASE-IN?

A It has serious implications. PECO's phase-in proposal could remain in effect for up to six years. If the utility opts not to file a base rate case during the pendency of the phase-in, then the proposed rate spread--which is based on PECO's erroneous

cost-of-service study--would be perpetuated despite its obvious inequities. Thus, it would not be appropriate, in my opinion, to develop a permanent rate spread which would remain in effect for possibly up to six years, particularly when the cost-of-service study results are significantly affected by the abnormal summer of 1984 peak day weather conditions.

Q HOW CAN THIS PROBLEM BE RESOLVED IN THE CONTEXT OF A PHASE-IN?

A My recommendation would be that the Commission not allow automatic rate increases if a phase-in plan is adopted. As Mr. Randall Falkenberg (of Kennedy & Associates) testifies (on behalf of PAIEUG), automatic recovery assumes that all factors affecting the revenue requirement and rate spread stay the same. Thus, under an automatic plan, it is possible for a utility to earn excess returns if for example, the required cost of equity decreases, O&M expenses increase by a lesser amount, or if sales volumes increase beyond those expected. Similarly, Dr. Bloom has demonstrated that weather-related factors can significantly affect the demand allocation factors and, thus, the class rates of return in a cost-of-service study. If PECO were to conduct a cost-of-service study for the year 1987 based on 1985 weather conditions, the results would be substantially different from those derived in the test year cost-of-service study filed in this Docket (based on the abnormal 1984 summer peak day weather conditions).

Thus, there could be a significant risk that, by preserving

the rate spread developed in this Docket throughout the pendency of the phase-in could result in a significant worsening of the revenue/cost relationships. Because of the simplistic rate spread and rate design aspect of an automatic recovery program, there is no assurance that the rates in the future would continue to adhere to cost.

Therefore, I recommend that the Commission order PECO to file updated cost-of-service studies if a phase-in plan is adopted. The purpose of these updated studies would be to ensure that the rates continue to reasonably adhere to costs during the pendency of the phase-in. To the extent that these subsequent cost-of-service studies demonstrated that rates were deviating from cost, then the Commission should have the ability to modify the rate spread adopted in this Docket.

COST OF SERVICE SHOULD BE THE PRIMARY BASIS FOR DETERMINING THE RATE SPREAD AND RATE DESIGN

Q WHAT CRITERIA SHOULD BE USED TO DETERMINE BOTH THE RATE SPREAD AND RATE DESIGN?

A Although other factors may be considered, such as gradualism, ease of administration and simplicity, primary emphasis should be placed on the cost of providing service to determine the revenue requirements from each class (rate spread) and from each customer within a class (rate design). The basic reasons for adhering to the cost-of-service principle throughout the revenue allocation and rate design processes are equity, engineering efficiency (cost-minimization),

stability and conservation.

Rates which reflect primarily cost-of-service considerations are equitable because each customer pays what it costs the utility to serve him, no more and no less. If rates are not based on costs, then some customers must pay part of the costs of providing service to other customers, which is inequitable.

With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, the utility has an incentive to construct the most economical mix of plants, and customers are provided with the proper incentive to minimize their costs, which will in turn minimize the costs to the utility.

When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns would result in parallel changes in revenues and expenses. Cost-based rates also provide a more stable basis for determining future levels of power costs. If rates are based, instead, on vague social policies, it becomes much more difficult to translate expected utility-wide cost changes into changes in the rates charged to particular customer classes. This added element of uncertainty will lessen the attractiveness of industrial expansion either by new or existing industries.

To the extent that rates do not reflect cost, multi-plant firms will be encouraged to shift production from high energy cost plants to lower energy cost plants in order to remain competitive.

Such a shifting of production would reduce employment and the overall contribution of the manufacturing concern to the state and local economy. This would, in turn, be self-defeating to the presumed beneficiaries of below-cost electric rates.

Finally, by providing balanced price signals against which to make consumption decisions, cost-based rates encourage conservation (of both capacity and energy), which is properly defined as the avoidance of wasteful or inefficient use (and not just less use). If rates are not based on costs, then the choices are distorted.

Q HOW HAS PECO PROPOSED TO ALLOCATE THE INCREASE AMONG THE CUSTOMER CLASSES?

A According to Mr. Williams, the increase was spread among the various rate classifications in proportion to base revenues, except (1) where the index of return would exceed 140%, (2) for SEPTA and AMTRAK (whose rates of return were set at the system average), and (3) for those classes whose index of return would increase relative to present rates. This resulted in the rate spread shown in Exhibit JP-1 ( ), Schedules 3 and 4.

In Schedule 3, the proposed net revenue increase is measured relative to base revenues by rate schedule.

Schedule 4, Page 1, shows the spread of the increase (before fuel savings) measured relative to nonfuel revenue. The latter is derived in Schedule 4, Page 2. This is, of course, a more meaningful comparison of the relative impact of a nonfuel-related increase.

PECO's proposed rate spread would result in above-average percent increases to Rate PD and Rate HT and below-average percent increases to the remaining rate schedules.

Q IS THIS A DIFFERENT RATE SPREAD APPROACH THAN PECO PROPOSED IN ITS LAST SEVERAL RATE CASES?

A Yes, it is. In the last three PECO rate proceedings, PECO proposed (and the Commission approved) to spread the increase relative to a proportion of revenue from each rate classification after all fuel revenue was removed. This approach was modified for those customer classes whose rates of return were either: (1) less than the system average or (2) greater than 130% to 140% of the system average rate of return. The stated objectives behind this approach were:

(1) To narrow the gap between class rates of return and the system average rate of return,

(2) To avoid any disruptive changes in the pattern of rates which would unduly affect any one customer class,

(3) To recognize the fact that energy costs do not contribute to the present need for additional revenue, and

(4) To be consistent with the methodology approved by the Commission.

In approving PECO's rate spread methodology, the Commission stated that:

> "Increased fuel costs are recovered in the ECR, and are not part of the base revenue increase at issue in this proceeding. Fuel revenue therefore should not be considered in allocating a rate increase related solely to nonfuel costs. The

Company's proposal accomplishes this result by removing all fuel revenue before allocating the increase." (PECO St. 10B, Page 3; Opinion and Order, Page 138, in Docket No. R-842590)

Thus, PECO's rate spread proposal in this Docket differs substantially from its proposals in prior rate cases and Commission precedent.

Q WOULD PECO'S PROPOSED RATE SPREAD MOVE THE RATES OF EACH CLASS SYSTEMATICALLY CLOSER TO COST?

A No, based on the PAIEUG et al revised 4CP cost-of-service study, the rates would not move closer to cost in most instances, as demonstrated in Exhibit JP-1 ( ), Schedule 1, Page 2. The lack of movement toward cost under the revised cost study is illustrated below:

PAIEUG et al Revised Cost-of-Service Study Results at Present and Proposed Rates

Rate Class	Index of Return		Interclass Subsidy		Movement Toward Cost
	Present Rates	Proposed Rates	Present Rates ($Millions)	Proposed Rates ($Millions)	
High Tension	99	109	$ -3.6	$ 55.7	No
Primary	116	113	11.4	18.2	No
Secondary	126	115	32.1	37.8	No
Residential	84	86	-58.0	-100.4	No
Street Lighting	198	106	9.4	1.2	Yes
SEPTA	119	97	1.3	-0.4	Yes
AMTRAK	144	99	3.8	-0.1	Yes
Other	122	66	3.6	-12.0	No

Q WHAT ARE THE INDEX OF RETURN AND THE INTERCLASS SUBSIDY?

A The index of return and the interclass subsidy are two other ways to measure the results of a cost-of-service study, besides rate of return.

The index of return is a measure of the relative rates of return of each class vis-a-vis the total Company rate of return. An index below 100 indicates that a class's revenues are not sufficient to recover its cost of service, while an index above 100 indicates that a class is being overcharged relative to cost. Mathematically, the index is derived by dividing each class's rate of return by the total Company rate of return.

The interclass subsidy is an annual statistic which measures the difference between the revenues required from each class and the revenues actually recovered. A negative amount indicates that a class is being subsidized each year (revenues are below cost), while a positive amount indicates that a class is providing a subsidy each year (revenues are above cost).

Q ARE THERE ANY OTHER PROBLEMS WITH PECO'S PROPOSED RATE SPREAD?

A Yes, there are. First, the nonjurisdictional class (other utilities) would be providing a substantially below-average rate of return. Unless this return is brought up to the system average, the retail classes would be subsidizing PECO's nonjurisdictional sales.

Second, it is obvious that some classes are receiving more favorable treatment than others. This is evident from the fact that, under PECO's rate spread, the street lighting, SEPTA and

AMTRAK rates would be moved significantly closer to cost, while just the opposite would occur for other classes. If PECO's objective is to move the rates of return closer to the average, then it should do so for all classes and not pick and choose to accomplish some arbitrary end result.

Q WHICH MEASURE--THE INDEX OF RETURN OR THE INTERCLASS SUBSIDY--IS THE MORE APPROPRIATE BASIS FOR DETERMINING WHETHER THE RATES WOULD BE MOVED CLOSER TO COST?

A The interclass subsidy is the more appropriate basis to determine whether rates are being moved closer to cost. Under some circumstances, the index of profitability could move closer to 100, but the interclass subsidy could either remain the same or increase.

For example, based on the PAIEUG et al revised cost-of-service study, the index of return from the secondary class would be 126 at present rates and 116 at proposed rates. However, the annual revenue subsidies--the difference between actual revenues and required revenues--would be $32,095,000 at present rates and $37,841,000 at proposed rates per year. This represents an increase of $5,700,000. Since the dollar subsidy would increase, this would not indicate a movement toward cost despite the fact that the relative rate of return would be closer to 100 (unity).

Thus, although the indexes of return create the appearance that rates are generally being moved closer to cost, this movement may only be an illusion if the interclass subsidies actually

increase.

Q WOULD YOUR ANSWER BE THE SAME BASED ON THE RESULTS OF PECO'S COST-OF-SERVICE STUDIES?

A Yes, it would. Even based on its (flawed) study, PECO's proposed rate spread would not systematically move all customer classes toward cost, not to mention that the rates would move farther from cost for three of the major classes--primary, secondary and residential. In fact, it is obvious that some classes (i.e., street lighting, SEPTA and AMTRAK) would be receiving more favorable treatment because their rates would move much closer to cost than would the other classes.

Q HAVE YOU DEVELOPED AN ALTERNATIVE INTERCLASS REVENUE ALLOCATION WHICH WOULD BETTER ACHIEVE THE OBJECTIVE OF MOVING ALL CLASSES SYSTEMATICALLY CLOSER TO COST?

A Yes, I have. This alternative recommendation is shown in Exhibit JP-1 ( ), Schedule 5.

The approach was similar to the rate spread methodology approved by the Commission in prior PECO rate cases. Specifically, I am recommending that the nonfuel increase be spread among the various rate schedules relative to nonfuel revenues provided that (1) the interclass revenue subsidy is either maintained or reduced relative to the subsidy at present rates, and (2) the index of return does not exceed 140% of the system average return. By at

least maintaining the subsidies for all classes, my proposed rate spread would prevent some classes from receiving more favorable treatment at the expense of others.

Q WOULD THE RATES MOVE CLOSER TO COST UNDER YOUR RECOMMENDED INTER-CLASS REVENUE ALLOCATION?

A In general, the rates would not be moved closer to cost because the interclass subsidies would not change. However, the recommended spread would be preferable (in terms of adhering to the cost-of-service study results) to PECO's proposal as shown in Exhibit JP-1 ( ), Schedule 6, and as demonstrated below:

PAIEUG et al's Revised Cost-of-Service Study Results
at Proposed and Recommended Rates

	Index of Return		Interclass Subsidy	
Rate Class	Proposed Rates	Recommended Rates	Proposed Rates ($Millions)	Recommended Rates ($Millions)
High Tension	109	100	$ 55.7	$ -
Primary	113	108	18.2	11.4
Secondary	115	113	37.8	32.1
Residential	86	92	-100.4	-56.1
Street Lighting	106	140	1.2	7.5
SEPTA	97	109	-0.4	1.3
AMTRAK	99	122	-0.1	3.8
Other	66	100	-12.0	-

Q IS NOT YOUR RECOMMENDED RATE SPREAD INAPPROPRIATE BASED ON THE MAGNITUDE OF THE RATE INCREASE WHICH PECO IS SEEKING IN THIS DOCKET?

A No, it is not. Although the magnitude of the total increase is quite large relative to prior PECO rate increases, this would be

equally true for all rate classes assuming that the entire increase is awarded in full at the end of this Docket. However, it is for this very reason that PECO has proposed a phase-in. Because the proposed phase-in would provide for substantial rate moderation, there is no valid reason not to spread the increase in a manner which would more closely adhere to the cost-of-service study results. The recommended rate spread would better accomplish this objective than would PECO's proposal, while, at the same time, not result in an overly-abrupt increase for any rate classification.

Q IF THE COMMISSION WERE TO AWARD A SMALLER INCREASE THAN PECO HAS REQUESTED, HOW SHOULD THIS SMALLER INCREASE BE SPREAD AMONG THE VARIOUS RATE CLASSIFICATIONS?

A My recommendation would be to follow the same procedure as described earlier. Specifically, the increase should be spread on an equal percent basis relative to nonfuel revenues subject to the ~~three~~ two constraints as follows: 2-19-86 SJM

(1) The interclass subsidies should be maintained (or possibly reduced), and

(2) The index of return should not exceed 140% for any major class.

Further, these constraints should be applied in the context of a revised cost-of-service study which takes into account all of the Commission-approved adjustments to rate base, revenues and expenses.

PECO'S PROPOSED DESIGN
OF RATE HT SHOULD BE MODIFIED

Q WHAT MODIFICATIONS ARE YOU RECOMMENDING BE MADE TO PECO'S PROPOSED RATE HT?

A I am recommending three changes in PECO's proposed design of Rate HT. They include:

(1) A lower tail block energy charge (3.18¢ based on PECO's proposed rate spread),

(2) Higher voltage discounts for service delivered at 66 kV and higher (equal to 1% of the base capacity and energy charges), and

(3) An increase in the Rate HT curtailment credit (to at least $3.40 based on PECO's proposed rate spread and rate design).

The above recommendations are based on a continued application of cost-of-service principles in the rate design process, and at least two of the recommendations are supported by precedent.

Q TURNING FIRST TO THE RATE HT TAIL BLOCK ENERGY CHARGE, WHAT IS THE BASIS FOR RECOMMENDING A LOWER CHARGE THAN PECO HAS PROPOSED?

A Applying the same cost-of-service principles in the rate design process as were applied in the cost allocation process, it follows that the demand charges should basically recover demand-related costs, while the energy charges should basically recover energy-related costs.

Q DOES THE PRESENT TAIL BLOCK ENERGY CHARGE RECOVER ONLY ENERGY-RELATED COSTS?

A No, it does not. Referring to Exhibit JP-1 ( ), Schedule 7, Column 1, the present tail block energy charge was designed to recover 0.5725¢ per kWh of demand costs.

Q HOW MUCH DEMAND COSTS WOULD BE RECOVERED IN THE PROPOSED TAIL BLOCK ENERGY CHARGE?

A Schedule 7, Column 2, shows that the demand cost recovery would be 1.1460¢ per kWh. This is more than 100% higher than the demand cost recovery at present rates. By contrast, the nonfuel energy-related component would increase by only 53%.

Q ISN'T THIS SIMPLY A REFLECTION THAT DEMAND-RELATED COSTS ARE INCREASING FASTER THAN NONFUEL ENERGY-RELATED COSTS?

A No, not entirely. PECO is only proposing to increase the capacity charge by about 76%. Thus, the proposed increase in the demand cost recovery within the tail energy block would substantially exceed the increase in demand-related costs. The result would be that more demand-related costs would be recovered in the tail energy block.

Q WHAT ARE THE CONSEQUENCES OF INCREASING THE RECOVERY OF DEMAND COSTS THROUGH AN ENERGY CHARGE?

A Increasing the recovery of demand-related costs in the tail block energy charge could exacerbate the problem of revenue and income instability. For example, if the level of kilowatthour sales

decreases (as often happens during an economic downturn), the utility's revenues will drop more than its costs because the demand costs will still be incurred since they are fixed. On the other hand, if the energy charge recovers basically energy-related costs, then the decline in revenues should parallel the corresponding decline in costs (because the energy charges basically recover only those costs which do, in fact, vary with the number of kilowatt-hours sold).

Q ISN'T PECO'S PROPOSED TAIL BLOCK ENERGY CHARGE BASED ON A DETAILED COST ANALYSIS?

A Yes, it is. However, as Dr. Bloom testifies, the cost analysis used for rate design purposes (i.e., the Bary curve) is not consistent with the demand cost allocation method (i.e., the 4CP method) which was used to determine class revenue requirements. (A more detailed description of this inconsistency appears in Dr. Bloom's testimony.)

Q WHAT IS YOUR RECOMMENDATION?

A My recommendation would be to maintain the level of demand cost recovery which is reflected in the present tail block energy charge (of .5725¢ per kWh). This would result in a charge of 3.18¢ per kWh. Because this is lower than the 3.75¢ charge which PECO is proposing, the revenue shortfall should be recovered through the capacity charge. This would result in a capacity charge of $10.40

per kW, as shown in Exhibit JP-1 ( ), Schedule 8, Column 1, based on PECO's proposed rate spread. If PAIEUG et al's recommended rate spread is adopted, then the capacity charge should be $10.19, as shown in Column 2. Alternatively, the percent increase in the tail block energy should be no higher than the percent increase in the first and second energy blocks, excluding embedded fuel cost. This alternative is shown in Column 3.

The rate values shown in Schedule 8 assume that PECO is awarded the full increase which it is proposing (before the phase-in) and that the recommended changes in the high voltage discount and curtailable credit are adopted.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDED CUSTOMER CHARGE?

A The $281.50 customer charge reflects the customer-related cost of service of the high tension class.

Q TURNING TO THE HIGH VOLTAGE DISCOUNT, WHAT IS THE NATURE OF THE CHANGE WHICH YOU ARE RECOMMENDING?

A My recommendation is to increase the high voltage discount so that Rate HT customers taking service at 66,000 volts and higher receive an additional credit of 1% of the base capacity and energy charges. The basis for the recommendation is to better reflect the cost differential of providing service at the various delivery voltages at which service is provided under Rate HT. These cost differences would arise because: (1) PECO incurs lower demand and energy losses

to provide service at higher delivery voltages (66,000 volts, 133,000 volts, et cetera) and (2) it need not install lower voltage facilities (i.e., 33,000 volts, 13,200 volts, et cetera) to serve higher voltage Rate HT customers.

The present structure of Rate HT only recognizes the transformation costs which PECO avoids by providing service at the higher delivery voltages. It does not reflect the differences in demand and energy losses, and it may not take into account costs other than transformation which PECO avoids in providing service at higher delivery voltages. Thus, ignoring the existing and proposed high voltage discounts, two customers having identical billing demands and kilowatthour consumption would pay the same for electricity even though they may be served at different high tension delivery voltages.

Q CAN YOU CITE ANY OTHER EXAMPLES WHERE SUCH ADDITIONAL VOLTAGE DISCOUNTS ARE IN PLACE?

A Yes. Two examples that come to mind are Pennsylvania Power Company and Pennsylvania Power & Light Company.

Pennsylvania Power Company's General Service-Transmission Rate Schedule (GT) is the equivalent of PECO's Rate HT. Service under Rate Schedule GT is provided at nominal transmission voltages of 23,000 volts or above. However, the stated capacity and energy charges are clearly applicable to service which is provided at 23,000 volts. An additional discount of 3% is applied to the

capacity and energy charge when service is provided at 69,000 volts, while a 5% discount is applied when service is provided at 138,000 volts.

In the case of Pennsylvania Power & Light Company, there are two separate tariff schedules for high tension customers, LP-4 and LP-5. Rate LP-5 is applicable to service provided at 66,000 volts or higher. Rate LP-4 is applicable at lower high tension delivery voltages (e.g., 13,200 volts, 33,000 volts, et cetera). Comparing the cost of electricity between the two rates, it is apparent that the higher voltage customers served on Rate LP-5 are paying less than Rate LP-4 customers of a comparable size and load factor.

Thus, the incorporation of an additional 1% discount on the capacity and energy charges for 66,000-volt and higher service is conservative and should be regarded as an initial step. Because PECO has not quantified the demand and energy loss differences within Rate HT and because there may be additional costs avoided (other than transformation costs), the utility should be ordered to develop certain additional cost-of-service and rate design data in its next rate case including:

(a) Coincident and noncoincident peak demands.

(b) Energy sales, billing demand and demand subject to the high voltage discount.

(c) The avoided transformation and other distribution costs at the higher delivery voltages.

(d) The differences in both demand and energy losses.

The above information should make it possible to refine the determination of the demand and energy cost differentials by delivery voltage within the high tension class.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT THE RATE HT CURTAILMENT CREDIT BE INCREASED TO AT LEAST $3.40?

A This recommendation is designed to maintain the relationship between firm and curtailable service which presently exists. Because PECO is proposing no increase in the $2.00 per kW credit, there would be a significant reduction in the relative cost differential, as shown in Exhibit JP-1 ( ), Schedule 9, Page I.

For example, at present rates, the $2.00 per kW credit is about 15% of the effective Rate HT demand charge above 300 hours' use. At proposed rates, the effective demand credit would be only 9%. (The effective demand charge is derived on Page 2, and it is equal to the sum of the capacity charge and the demand costs recovered in the first two energy blocks. Page 3 demonstrates that, above 300 hours' use, Rate HT is equivalent to a flat rate having a capacity charge of $13.515 per kW and an energy charge of $.0376 per kWh.)

Comparing the monthly nonfuel cost for a hypothetical customer having a 10,000-kW maximum registered demand operating at a 90% load factor (Schedule 9, Page 1), the present credit for curtailable service would be 4.6%. This would be reduced to 2.7% at proposed rates. Thus, with no increase in the curtailment credit,

curtailable service would become even less attractive than is presently the case. It should be noted that, when the curtailment credit was first implemented, the effective demand credit was 20%.

Q WHAT CURTAILMENT CREDIT WOULD BE NECESSARY TO MAINTAIN THE EXISTING RELATIONSHIP BETWEEN CURTAILABLE AND FIRM SERVICE?

A Based on PECO's proposed rate spread and rate design, a credit of at least $3.40 per kW would maintain the cost differential between curtailable and firm service, as shown in Exhibit JP-1 ( ), Schedule 10, Column 1. To the extent that either the rate spread or rate design is altered, then the amount of the curtailment credit should also be revised to maintain a consistent relationship, as shown in Columns 2 and 3 of Schedule 10.

Q ARE THERE ANY EXAMPLES WHICH SUPPORT YOUR RECOMMENDATION TO INCREASE THE CURTAILMENT CREDIT?

A Yes. Pennsylvania Power & Light recently implemented Rate Schedule IS-2, which is characterized as a High Load Factor--Interruptible Service Schedule. This rate is for large general service customers who would otherwise take firm electric service on Rate Schedule LP-5. Assuming a customer having a 10,000-kW demand, operating at a 90% load factor and with a firm capacity requirement of 5,500 kW, the cost differential (excluding embedded fuel) would be about 7%. This is much higher than the effective curtailable credit provided by PECO at present rates. Further, the terms and conditions of

PP&L's rate are similar to those in PECO's HT Curtailment Rider.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock, 605 Old Ballas Road, St. Louis, Missouri.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and am employed by Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I am a graduate of Washington University. I hold the degrees of Bachelor of Science in Electrical Engineering and Master of Business Administration. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft. Upon graduation, in June, 1975, I joined the firm of Drazen-Brubaker & Associates, Inc. My work consists of preparation of financial and economic studies relating to electric and gas utilities, including revenue requirements, cost-of-service studies, rate design, and contract analysis.

I have testified before the regulatory commissions of Alabama, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana,

Minnesota, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas and Washington. I have also appeared before the Board of Public Utilities of Kansas City, Kansas, and before the Bonneville Power Administration.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. In the last five years, our firm has participated in more than 700 rate cases in forty states and Canada.

The firm provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. In addition, we have also prepared depreciation and feasibility studies relating to utility service. In all these cases, it was necessary to analyze the utility's operating and financial records, including property records, depreciation studies, revenues, expenses and taxes. We also assist in the negotiation of contracts for utility service for large users.

In general, we are engaged in regulatory consulting, economic studies and contract negotiation.

PHILADELPHIA ELECTRIC COMPANY

Exhibits

of

JERRY POLLOCK

On behalf of the

Philadelphia Area Industrial Energy User Group

Allied Corporation, Fibers Division
Boeing Vertol Company
B.P. Oil, Inc.
The Budd Company
Liquid Air Corporation of North America
Lukens Steel Company
Nabisco Brands, Inc.
SPC (a Burroughs Company)
SmithKline Beckman Corporation
Sun Refining and Marketing Company
3M Company)

and

United States Steel Corporation

January 1986
Project 4035

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

PHILADELPHIA ELECTRIC COMPANY

Summary of PECO's Cost-of-Service Study Results
at Present and Proposed Rates
Four Coincident Peak Method
Year Ending June 30, 1986

Line	Customer Class	Rate of Return		Index of Return		Interclass Subsidy	
		Present Rates (1)	Proposed Rates (2)	Present Rates (3)	Proposed Rates (4)	Present Rates (000) (5)	Proposed Rates (000) (6)
1	High Tension	5.37%	12.23%	84	96	$(53,079)	$(24,632)
2	Primary	6.21	12.40	97	98	(2,111)	(3,704)
3	Secondary	8.07	14.70	126	116	32,947	39,194
	Residential:						
4	Heating	7.39	14.69	116	116	6,463	12,751
5	Regular	6.14	12.15	96	96	(11,183)	(24,495)
6	Rate OP	21.95	30.97	344	244	5,114	6,006
7	Total Res.	6.39	12.59	100	99	394	(5,738)
	Street Lighting:						
8	Rate SLP	11.12	12.31	174	97	2,936	(242)
9	Rate SLS	13.15	13.70	206	108	5,541	822
10	All Other	18.95	20.51	297	161	866	539
11	Total St. Ltg.	12.58	13.44	197	106	9,343	1,119
12	Other Utilities	9.55	9.55	149	75	5,830	(5,818)
13	Interdepartmental	11.16	11.16	175	88	1,307	(421)
14	SEPTA	7.86	12.70	123	100	1,522	0
15	AMTRAK	9.23	12.70	144	100	3,847	0
16	Total Company	6.39%	12.70%	100	100	$ -	$ -

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present and Proposed Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	Rate of Return		Index of Return		Interclass Subsidy	
		Present Rates (1)	Proposed Rates (2)	Present Rates (3)	Proposed Rates (4)	Present Rates (000) (5)	Proposed Rates (000) (6)
1	High Tension	6.31%	13.88%	99	109	$(3,623)	$ 55,678
2	Primary	7.44	14.38	116	113	11,377	18,161
3	Secondary	8.02	14.63	126	115	32,095	37,841
	Residential:						
4	Heating	5.94	12.25	93	96	(3,352)	(3,346)
5	Regular	5.18	10.62	81	84	(59,750)	(103,109)
6	Rate OP	22.31	31.47	349	248	5,160	6,081
7	Total Res.	5.38	10.95	84	86	(57,942)	(100,374)
	Street Lighting:						
8	Rate SLP	11.20	12.39	175	98	2,965	(191)
9	Rate SLS	13.18	13.74	206	108	5,555	849
10	All Other	19.14	20.72	300	163	873	549
11	Total St. Ltg.	12.64	13.50	198	106	9,392	1,207
12	Other Utilities	7.31	7.31	114	58	2,044	(11,981)
13	Interdepartmental	12.68	12.68	198	100	1,562	(6)
14	SEPTA	7.59	12.32	119	97	1,276	(402)
15	AMTRAK	9.17	12.61	144	99	3,817	(122)
16	Total Company	6.39%	12.70%	100	100	$ -	$ -

PHILADELPHIA ELECTRIC COMPANY

Comparison of Cost-of-Service Study Results
Four Coincident Peak Method

Line	Rate Class	Last Case* (R-842590) (1)	This Case (R-85012) PECO (2)	This Case (R-85012) PAIEUG et al (3)
1	Test Year: Costs	Dec. 1984	- - - June, 1986 - - -	
2	Alloc. Factors	1982	1984	
	Index of Return			
3	High Tension**	116	86	100
4	Primary	140	97	116
5	Secondary	140	126	126
6	Residential	71	100	84
7	Street Lighting	90	197	198
Source:		PAIEUG Exhibit 1, Schedule 3	WFS-1, Pages 6 and 6a	JP-1, Schedule 1, Page 2

*At PECO's proposed rates

**Includes SEPTA and AMTRAK

PHILADELPHIA ELECTRIC COMPANY

Distribution of Proposed Net Revenue Increase
Relative to Present Base Revenue
Year Ending June 30, 1986

Line	Rate Schedule	Present Base Revenue (000) (1)	Net Revenue Increase Amount (000) (2)	Percent (3)	Index (4)
1	R	$ 739,467	$219,206	29.6%	105
2	RH	127,424	33,003	25.9	92
3	OP	25,989	0	0.0	0
4	POL	1,527	0	0.0	0
5	GS	344,838	102,204	29.6	105
6	PD	191,010	56,630	29.6	105
7	HT	860,983	255,086	29.6	105
8	EPA	31,683	1,471	4.6	16
9	EPS	20,100	2,988	14.9	53
10	SLP	14,993	0	0.0	0
11	SLS	18,129	0	0.0	0
12	TL	3,486	0	0.0	0
13	BLI	7	2	28.6	101
14	TRR	306	89	29.1	103
15	Subtotal	$2,379,942	$670,679	28.2%	100
16	Other Elec. Operations	122,051	11,081	9.1	32
17	Total Company	$2,501,993	$681,760	27.2%	-

PHILADELPHIA ELECTRIC COMPANY

Distribution of Proposed Nonfuel Revenue Increase
Relative to Present Nonfuel Revenue
Year Ending June 30, 1986

Line	Rate Schedule	Present Nonfuel Revenue* (000) (1)	Proposed Nonfuel Revenue Increase Amount (000) (2)	Percent (3)	Index (4)
1	R	$ 553,553	$267,733	48.4%	87
2	RH	83,049	44,585	53.7	97
3	OP	14,672	2,954	20.1	36
4	POL	1,288	62	4.8	9
5	GS	246,883	127,772	51.8	93
6	PD	126,575	73,449	58.0	105
7	HT	495,926	350,372	70.6	127
8	EPA	19,276	4,709	24.4	44
9	EPS	12,380	5,003	40.4	73
10	SLP	11,998	782	6.5	12
11	SLS	16,380	457	2.8	5
12	TL	2,541	247	9.7	18
13	BLI	5	2	47.3	85
14	TRR	306	89	29.1	52
15	Subtotal	$1,584,832	$878,216	55.4%	100
16	Other Elec. Operations	107,964	14,758	13.7	-
17	Total Company	$1,692,796	$892,974	52.8%	-

*Page 2 of 2

PHILADELPHIA ELECTRIC COMPANY

Derivation of Nonfuel Revenue at Present Rates
Year Ending June 30, 1986

Line	Rate Schedule	Energy Sold (MWh) (1)	Present Base Revenue (000) (2)	Embedded Energy Costs* (000) (3)	Present Nonfuel Revenue (000) (4)
1	R	6,465,900	$ 739,467	$185,914	$ 553,553
2	RH	1,543,300	127,424	44,375	83,049
3	OP	393,600	25,989	11,317	14,672
4	POL	8,320	1,527	239	1,288
5	GS	3,406,780	344,838	97,955	246,883
6	PD	2,241,000	191,010	64,435	126,575
7	HT	12,696,300	860,983	365,057	495,926
8	EPA	431,500	31,683	12,407	19,276
9	EPS	268,500	20,100	7,720	12,380
10	SLP	104,148	14,993	2,995	11,998
11	SLS	60,840	18,129	1,749	16,380
12	TL	32,880	3,486	945	2,541
13	BLI	62	7	2	5
14	TRR	0	306	0	306
15	Subtotal	27,653,130	$2,379,942	$795,110	$1,584,832
16	Other Elec. Operations	489,932	122,051	14,087	107,964
17	Total Company	28,143,062	$2,501,993	$809,197	$1,692,796

*Column (1) x 2.8753¢/kWh

PHILADELPHIA ELECTRIC COMPANY

PAIEUG et al Recommended
Distribution of Proposed Nonfuel Revenue Increase
Relative to Present Nonfuel Revenue
Year Ending June 30, 1986

Line	Rate Schedule	Present Nonfuel Revenue (000) (1)	Recommended Nonfuel Revenue Increase Amount (000) (2)	Percent (3)	Index (4)
1	R	$ 553,553	$310,723	56.1%	103
2	RH	83,049	45,639	55.0	101
3	OP	14,672	2,007	13.7	25
4	POL	1,288	62	4.8	9
5	GS	246,883	121,776	49.3	90
6	PD	126,575	66,957	52.9	97
7	HT	495,926	295,796	59.6	109
8	EPA	19,276	8,648	44.9	82
9	EPS	12,380	6,681	54.0	99
10	SLP	11,998	3,516	29.3	54
11	SLS	16,380	4,083	24.9	46
12	TL	2,541	247	9.7	18
13	BLI	5	2	38.3	70
14	TRR	306	89	29.1	53
15	Subtotal	$1,584,832	$866,228	54.7%	100
16	Other Elec. Operations	107,964	26,745	24.8	-
17	Total Company	$1,692,796	$892,973	52.8%	-

PHILADELPHIA ELECTRIC COMPANY

Summary of PAIEUG et al Revised Cost-of-Service Study Results
at Present, Proposed and Recommended Rates
Four Coincident Peak Method
1985 EDH Study
Year Ending June 30, 1986

Line	Customer Class	Rate of Return			Index of Return			Interclass Subsidy		
		Present Rates (1)	Proposed Rates (2)	Recommended Rates (3)	Present Rates (4)	Proposed Rates (5)	Recommended Rates (6)	Present Rates (000) (7)	Proposed Rates (000) (8)	Recommended Rates (000) (9)
1	High Tension	6.31%	13.88%	12.70%	99	109	100	$(3,623)	$ 55,678	$(16)
2	Primary	7.44	14.38	13.75	116	113	108	11,377	18,161	11,377
3	Secondary	8.02	14.63	14.33	126	115	113	32,095	37,841	32,095
	Residential:									
4	Heating	5.94	12.25	12.25	93	96	96	(3,352)	(3,346)	(3,352)
5	Regular	5.18	10.62	11.50	81	84	91	(59,750)	(103,109)	(57,924)
6	Rate OP	22.31	31.47	28.62	349	248	225	5,160	6,081	5,160
7	Total Res.	5.38	10.95	11.69	84	86	92	(57,942)	(100,374)	(56,116)
	Street Lighting:									
8	Rate SLP	11.20	12.39	17.51	175	98	131	2,965	(191)	2,389
9	Rate SLS	13.18	13.74	19.49	206	108	143	5,555	849	4,475
10	All Other	19.14	20.72	25.45	300	163	181	873	549	703
11	Total St. Ltg.	12.64	13.50	18.95	198	106	140	9,392	1,207	7,567
12	Other Utilities	7.31	7.31	12.70	114	58	100	2,044	(11,981)	0
13	Interdepartmental	12.68	12.68	12.70	198	100	100	1,562	(6)	0
14	SEPTA	7.59	12.32	13.91	119	97	109	1,276	(402)	1,276
15	AMTRAK	9.17	12.61	15.49	144	99	122	3,817	(122)	3,817
16	Total Company	6.39%	12.70%	12.70%	100	100	100	$ -	$ -	$ -

PHILADELPHIA ELECTRIC COMPANY

Analysis of PECO's Proposed Rate HT Tail Block Energy Charge

Line	Description	Present Rates (1)	Proposed Rates (2)	PECO Proposed Increase Amount (3)	PECO Proposed Increase Percent (4)
1	Base Rate	3.7600¢	3.7500¢	(0.0100)¢	- %
2	Less: Embedded Fuel Cost	2.8753¢	2.1248¢	(0.7505)¢	(26)%
3	Nonfuel Rate	0.8847¢	1.6252¢	0.7405 ¢	84 %
4	Nonfuel Energy-Related Cost[a]	0.3122¢	0.4792¢	0.1670 ¢	53 %
5	Demand Cost Recovery	0.5725¢	1.1460¢	0.5735 ¢	100 %

(a) Unit Energy Cost[b]

	3.1875¢	2.6040¢
Embedded Fuel	2.8753	2.1248
Nonfuel Energy Cost	0.3122¢	0.4792¢

(b) Exhibit WFS-1

In Docket No. R-842590	In Docket No. R-85012

PHILADELPHIA ELECTRIC COMPANY

PAIEUG Recommended Design of Rate HT
(Before Phase-In)

Line	Description	Based on PECO Proposed Rate Spread (1)	Based on PAIEUG Recommended Rate Spread	
			Recommended Tail Block (2)	Equal Percent (3)
1	Customer Charge	$264.15	$281.50	$281.50
2	Capacity Charge	$ 10.40	$ 10.19	$ 10.20
	Energy Charge:			
3	First 150 Hours' Use	$ .0964	$ .0944	$ .0924
4	Next 150 Hours' Use	.0668	.0655	.0636
5	Additional	.0318	.0318	.0352
	High Voltage Discount:			
6	33 kV	$ .07	$ .07	$ .07
7	66 kV	.30*	.30*	.30*
8	Over 66 kV	.30*	.30*	.30*

*Plus 1% of Capacity and Energy Charges.

Note: The above values also reflect the recommended Rate HT Curtailment Credits developed in Schedule 10.

PHILADELPHIA ELECTRIC COMPANY

Analysis of the Relationship Between
Firm and Curtailable Service
at Present Versus Proposed Rates

Line	Description	Present Rates (1)	Proposed Rates (2)
1	Rate HT Curtailment Credit ($/kW)	$ 2.00	$ 2.00
2	Effective Rate HT Capacity Charge ($/kW)[a]	$ 13.515	$ 22.670
3	Curtailment Credit	15%	9%
	Monthly Nonfuel Power Cost (10,000 kW Maximum Registered Demand at a 90% Load Factor)		
4	Curtailable Service[b]	$188,273	$327,532
5	Firm Service	$197,273	$336,532
6	Credit for Curtailable Service	4.6%	2.7%

(a) Page 2 of 3

(b) 5,500 kW Firm capacity demand

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Derivation of Rate HT Effective Demand Charge at 300 Hours' Use and Above for Present and PECO Proposed Rates

Line	Description	Present Rate (1)	Proposed Rate (2)
1	Capacity Charge ($ per kW)	$ 5.370	$ 9.440
	Energy Charge Less Tail Block:		
2	First 150 Hours' Use (per kWh)	.0363	.0589
3	Next 150 Hours' Use (per kWh)	.0180	.0293
4	Subtotal (per kWh)	.0543	.0882
5	Demand Component ($ per kW)(a)	8.145	13.230
6	Effective Capacity Charge ($ per kW)(b)	$13.515	$22.670

(a) Line 4 x 150 hours

(b) Line 1 + Line 5 (for proof that the Hours' Use and CDE formats are equivalent, refer to Page 3 of 3).

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Proof of Equivalence Between Hours' Use and CDE Format
(10,000 kW Demand at 90% Load Factor)

Line	Description	Billing Units (1)	Rate (2)	Amount (3)
	Hours' Use Format			
1	Capacity Charge	10,000	$ 5.37	$ 53,700
	Energy Charge:			
2	First 150 Hours' Use	1,500,000	.0739	110,850
3	Next 150 Hours' Use	1,500,000	.0556	83,400
4	Additional	3,570,000	.0376	134,232
5	Total			$382,182
	CDE Format			
6	Effective Capacity Charge	10,000	$13.515	$135,150
7	Energy Charge	6,570,000	.0376	247,032
8	Total			$382,182

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Recommended Rate HT Curtailment Credit

Line	Description	Based on PECO Allocation and Rate Design (1)	Based on PECO Allocation and PAIEUG Recommended Rate Design (2)	Based on PAIEUG Recommended Allocation and Rate Design (3)
1	Effective Rate HT Capacity Charge	$22.670	$25.340	$24.635
2	Curtailment Credit as a Percent of the Effective Capacity Charge	15%	15%	15%
3	Curtailment Credit	$ 3.40	$ 3.80	$ 3.70