MORGAN, LEWIS & BOCKIUS
COUNSELORS AT LAW
2000 ONE LOGAN SQUARE
PHILADELPHIA, PENNSYLVANIA 19103
TELEPHONE: (215) 963-5000
CABLE ADDRESS: MORLEBOCK
TELEX: 83-1315

WASHINGTON
NEW YORK
LOS ANGELES
MIAMI
HARRISBURG
LONDON

December 26, 1985

RECEIVED
DEC 26 1985
SECRETARY'S OFFICE
Public Utility Commission

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
North Office Building
Commonwealth and North Streets
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v.
Philadelphia Electric Company
Docket No. R-850152

Dear Secretary Rich:

Enclosed for filing with the Commission please find the original and nine copies of Petition of Philadelphia Electric Company for Commission Review and Answer A Material Question in the above-captioned docket.

As shown on the attached Certificate of Service, I have today served two copies of this document on all Active Parties.

Sincerely,

William E. Zeiter
Counsel for
Philadelphia Electric
Company

WEZ/gin

Enclosures

DOCUMENT FOLDER

DEC 26 1985
SECRETARY'S OFFICE
Public Utility Commission

CERTIFICATE OF SERVICE

I hereby certify that I have caused copies of the Petition of Philadelphia Electric Company for Commission Review and Answer to a Material Question filed on December 26, 1985 to be served by first class mail, postage prepaid on all active parties in the Limerick No. I Rate Proceeding.

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
New Filing Section
Secretary's Bureau, Room B-18
North Office Building
Commonwealth and North Streets
Harrisburg, PA 17120

John Hanger, Esquire
Community Legal Services, Energy Project
3638 North Broad Street
Philadelphia, PA 19140

David M. Kleppinger, Esquire
100 Pine Street
Harrisburg, PA 17120

Zori G. Ferkin, Esquire
Governor's Energy Council
P.O. Box 8010
300 N. 2nd Street
Harrisburg, PA 17105

Scott Rubin, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

Mildred E. V. Pitts, Esquire
Information Resources & Utilities Division
General Services Administration
Room 4002
18th and F Streets, N.W.
Washington, DC 20405

Charles E. Rainey, Jr., Esquire
Municipal Services Building
Law Department, 15th Floor
Philadelphia, PA 19102

Edward S. Wardell, Esquire
Constance B. Foster, Esquire
Dilworth, Paxson, Kalish & Kaufman
2600 The Fidelity Building
Philadelphia, PA 19109-1094

Nancy Schuster, Esquire
1 Pond Street
Bristol, PA 19007

Patricia M. Gustin
Pennsylvania Public Utility Commission
Room G-33
North Office Building
Harrisburg, PA 17108

Earle H. O'Donnell, Esquire
Merrill L. Kramer, Esquire
Sutherland, Asbill & Brennan
1666 K Street, N.W.
Washington, D.C. 20006-2803

Mark P. Widoff, Esquire
Widoff, Reager, Selkowitz & Adler
129 State Street
Harrisburg, PA 17101

Michael Browne, Esquire
Reed, Smith, Shaw & McClay
1600 Avenue of the Arts Building
Broad and Chestnut Streets
Philadelphia, PA 19107

Honorable Joseph P. Matuschak
Pittsburgh State Office Building
300 Liberty Avenue
Pittsburgh, PA 15222

Wayne L. Emery, Esquire
Kenneth R. Pepperney, Esquire
Rafael Caminero, Esquire
600 Grant Street, Rm. 1580
Pittsburgh, PA 15230

Alan R. Squires, Esquire
Greenstein, Gorelick, Price,
Silverman & Laveson
900 Two Penn Center Plaza
Philadelphia, PA 19102

WE Zeiter

William E. Zeiter
Counsel for Philadelphia
Electric Company

RECEIVED

DEC 26 1985

SECRETARY'S OFFICE
Public Utility Commission

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

PETITION OF PHILADELPHIA ELECTRIC COMPANY FOR COMMISSION REVIEW AND ANSWER A MATERIAL QUESTION

WILLIAM E. ZEITER
Counsel for
PHILADELPHIA ELECTRIC COMPANY

OF COUNSEL
Edward G. Bauer, Jr., Esquire
Vice President & General Counsel
PHILADELPHIA ELECTRIC COMPANY
3201 Market Street
Philadelphia, PA 19101

J.H. Calvert, Jr.
Walter R Hall, II
Frederick H. Knight
David B. MacGregor
Robert H. Young
MORGAN, LEWIS & BOCKIUS
2000 One Logan Square
Philadelphia, PA 19103

DOCKETED
DEC 27 1985

DOCUMENT FOLDER

December 26, 1985

NOW COMES Philadelphia Electric Company ("PECO"), pursuant to Section 5.302 of the Commission's Regulations (52 Pa. Code Section 5.302), and Petitions your Honorable Commission to grant interlocutory review and answer a material question. The material question for which this Petition seeks Commission review and answer has arisen as a result of an ALJ ruling granting a Motion in Limine filed by Trial Staff which would exclude certain as yet unspecified PECO testimony setting forth the prudent reasons for the 1976 and 1978 Limerick construction delays. The ruling is based on the novel view that the PUC discussion on the subject in the Limerick Investigation, 56 Pa. PUC 47 (1982) ("1980 Limerick Investigation"), must be conclusive upon the parties in this proceeding because the 1980 Limerick Investigation is a bifurcation or ancillary or in-aid aspect of this rate case.

The material question for which this Petition seeks Commission review and answer is the following:

> Whether, contrary to the determination of the Pennsylvania Supreme Court in Pa. P.U.C. v. Philadelphia Electric Company, 501 Pa. 153, 460 A.2d 734 (1983), the criticism of the Company's 1976 and 1978 deferral announcements in the 1980 Limerick Investigation constituted a final adjudication which precludes the submission of any evidence on the prudence of such action in the current proceeding, other than quantification of the consequences thereof.

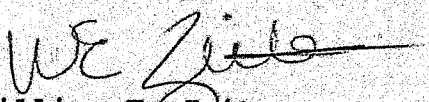
Justice requires a negative answer to the material question. PECO raised this very issue in the appellate proceedings which followed the 1980 Limerick Investigation in order to avoid any res judicata or other conclusive status for

the imprudence discussion and was told by the Pennsylvania Supreme Court that the PUC opinion was "advisory" and that such "mere criticism" did not constitute an adjudication and could not be reviewed on appeal. Extraordinary circumstances require that the PUC permit this interlocutory review because:

1. To make the PUC's imprudence "criticism" a binding finding of fact in this case in the face of the Supreme Court's decision causes substantial prejudice to PECO whose due process rights are violated by (a) ruling that a "criticism" it could not appeal is final and binding, and (b) excluding evidence which forms the basis for a critical PECO position in this proceeding developed in reliance upon the Commission's prior statements and the Supreme Court decision.

2. Exclusion of major evidence on the prudence of the 1976 and 1978 Limerick deferral announcements will prejudice PECO by creating an incomplete record, certain to be reversed on appeal, with the need to add the excluded evidence at a later date, contrary to the orderly conduct of proceedings in which rates are to be established for the future.

Respectfully submitted,



William E. Zeiter
Counsel for Philadelphia
Electric Company

MORGAN, LEWIS & BOCKIUS
COUNSELORS AT LAW
2000 ONE LOGAN SQUARE
PHILADELPHIA, PENNSYLVANIA 19103
TELEPHONE: (215) 963-5000
CABLE ADDRESS: MORLEBOCK
TELEX: 83-1315

WASHINGTON
NEW YORK
LOS ANGELES

MIAMI
HARRISBURG
LONDON

December 27, 1985

RECEIVED
DEC 27 1985
SECRETARY'S OFFICE
Public Utility Commission

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
North Office Building
Commonwealth and North Streets
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v.
Philadelphia Electric Company
Docket No. R-850152

Dear Secretary Rich:

Enclosed for filing with the Commission please find the original and nine copies of Petition of Philadelphia Electric Company for Commission Review and Answer A Material Question in the above-captioned docket.

As shown on the attached Certificate of Service, I have today served two copies of this document on all Active Parties.

Sincerely,

William E. Zeiter
Counsel for
Philadelphia Electric
Company

WEZ/gin

Enclosures

DOCUMENT
FOLDER

MORGAN, LEWIS & BOCKIUS
COUNSELORS AT LAW
2000 ONE LOGAN SQUARE
PHILADELPHIA, PENNSYLVANIA 19103
TELEPHONE: (215) 963-5000
CABLE ADDRESS: MORLEBOCK
TELEX: 83-1315

WASHINGTON
NEW YORK
LOS ANGELES

MIAMI
HARRISBURG
LONDON

WILLIAM E. ZEITER
DIAL DIRECT (215) 963-5367

RECEIVED
DEC 30 1985
SECRETARY'S OFFICE
Public Utility Commission

December 26, 1985

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
North Office Building
Commonwealth and North Streets
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commision v.
Philadelphia Electric Company
Docket No. R-850152

Dear Secretary Rich:

Enclosed for filing with the Commission please find the original and nine copies of Petition of Philadelhia Electric Company for Commission Review and Answer A Material Question in the above-captioned docket.

As shown on the attached Certificate of Service, I have today served copies of this document on all Active Parties.

Sincerely,

William E. Zeiter
Counsel for
Philadelphia Electric
Company

WEZ/gin

Enclosures

RECEIVED
DEC 30 1985
SECRETARY'S OFFICE
Public Utility Commission

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

PETITION OF PHILADELPHIA ELECTRIC COMPANY FOR COMMISSION REVIEW AND ANSWER A MATERIAL QUESTION

WILLIAM E. ZEITER
Counsel for
PHILADELPHIA ELECTRIC COMPANY

OF COUNSEL
Edward G. Bauer, Jr., Esquire
Vice President & General Counsel
PHILADELPHIA ELECTRIC COMPANY
3201 Market Street
Philadelphia, PA 19101

J.H. Calvert, Jr.
Walter R Hall, II
Frederick H. Knight
David B. MacGregor
Robert H. Young
MORGAN, LEWIS & BOCKIUS
2000 One Logan Square
Philadelphia, PA 19103

December 26, 1985

DOCKETED
JAN 3 - 1986

DOCUMENT
FOLDER

NOW COMES Philadelphia Electric Company ("PECO"), pursuant to Section 5.302 of the Commission's Regulations (52 Pa. Code Section 5.302), and Petitions your Honorable Commission to grant interlocutory review and answer a material question. The material question for which this Petition seeks Commission review and answer has arisen as a result of an ALJ ruling granting a Motion in Limine filed by Trial Staff which would exclude certain as yet unspecified PECO testimony setting forth the prudent reasons for the 1976 and 1978 Limerick construction delays. The ruling is based on the novel view that the PUC discussion on the subject in the Limerick Investigation, 56 Pa. PUC 47 (1982) ("1980 Limerick Investigation"), must be conclusive upon the parties in this proceeding because the 1980 Limerick Investigation is a bifurcation or ancillary or in-aid aspect of this rate case.

The material question for which this Petition seeks Commission review and answer is the following:

> Whether, contrary to the determination of the Pennsylvania Supreme Court in Pa. P.U.C. v. Philadelphia Electric Company, 501 Pa. 153, 460 A.2d 734 (1983), the criticism of the Company's 1976 and 1978 deferral announcements in the 1980 Limerick Investigation constituted a final adjudication which precludes the submission of any evidence on the prudence of such action in the current proceeding, other than quantification of the consequences thereof.

Justice requires a negative answer to the material question. PECO raised this very issue in the appellate proceedings which followed the 1980 Limerick Investigation in order to avoid any res judicata or other conclusive status for the imprudence discussion and was told by the Pennsylvania Supreme Court that the PUC opinion was "advisory" and that such "mere criticism" did not constitute an adjudication and could not be reviewed on appeal. Extraordinary circumstances require that the PUC permit this interlocutory review because:

1. To make the PUC's imprudence "criticism" a binding finding of fact in this case in the face of the Supreme Court's decision causes substantial prejudice to PECO whose due process rights are violated by (a) ruling that a "criticism" it could not appeal is final and binding, and (b) excluding evidence which forms the basis for a critical PECO position in this proceeding developed in reliance upon the Commission's prior statements and the Supreme Court decision.

2. Exclusion of major evidence on the prudence of the 1976 and 1978 Limerick deferral announcements will prejudice PECO by creating an incomplete record, certain to be reversed on appeal, with the need to add the excluded evidence at a later date, contrary to the orderly conduct of proceedings in which rates are to be established for the future.

Respectfully submitted,

/s/ William E. Zeiter

William E. Zeiter
Counsel for Philadelphia Electric Company

CERTIFICATE OF SERVICE

I hereby certify that I have caused copies of the Petition of Philadelphia Electric Company for Commission Review and Answer to a Material Question filed on December 26, 1985 to be served by first class mail, postage prepaid on all active parties in the Limerick No. I Rate Proceeding.

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
New Filing Section
Secretary's Bureau, Room B-18
North Office Building
Commonwealth and North Streets
Harrisburg, PA 17120

John Hanger, Esquire
Community Legal Services, Energy Project
3638 North Broad Street
Philadelphia, PA 19140

David M. Kleppinger, Esquire
100 Pine Street
Harrisburg, PA 17120

Zori G. Ferkin, Esquire
Governor's Energy Council
P.O. Box 8010
300 N. 2nd Street
Harrisburg, PA 17105

Scott Rubin, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

Mildred E. V. Pitts, Esquire
Information Resources & Utilities Division
General Services Administration
Room 4002
18th and F Streets, N.W.
Washington, DC 20405

Charles E. Rainey, Jr., Esquire
Municipal Services Building
Law Department, 15th Floor
Philadelphia, PA 19102

Edward S. Wardell, Esquire
Constance B. Foster, Esquire
Dilworth, Paxson, Kalish & Kaufman
2600 The Fidelity Building
Philadelphia, PA 19109-1094

Nancy Schuster, Esquire
1 Pond Street
Bristol, PA 19007

Patricia M. Gustin
Pennsylvania Public Utility Commission
Room G-33
North Office Building
Harrisburg, PA 17108

Earle H. O'Donnell, Esquire
Merrill L. Kramer, Esquire
Sutherland, Asbill & Brennan
1666 K Street, N.W.
Washington, D.C. 20006-2803

Mark P. Widoff, Esquire
Widoff, Reager, Selkowitz & Adler
129 State Street
Harrisburg, PA 17101

Michael Browne, Esquire
Reed, Smith, Shaw & McClay
1600 Avenue of the Arts Building
Broad and Chestnut Streets
Philadelphia, PA 19107

Honorable Joseph P. Matuschak
Pittsburgh State Office Building
300 Liberty Avenue
Pittsburgh, PA 15222

Wayne L. Emery, Esquire
Kenneth R. Pepperney, Esquire
Rafael Caminero, Esquire
600 Grant Street, Rm. 1580
Pittsburgh, PA 15230

Alan R. Squires, Esquire
Greenstein, Gorelick, Price,
Silverman & Laveson
900 Two Penn Center Plaza
Philadelphia, PA 19102

William E. Zeiter
Counsel for Philadelphia
Electric Company

MORGAN, LEWIS & BOCKIUS
COUNSELORS AT LAW
2000 ONE LOGAN SQUARE
PHILADELPHIA, PENNSYLVANIA 19103
TELEPHONE: (215) 963-5000
CABLE ADDRESS: MORLEBOCK
TELEX: 83-1315

WASHINGTON
NEW YORK
LOS ANGELES

MIAMI
HARRISBURG
LONDON

FREDERICK H. KNIGHT, 3RD
DIAL DIRECT (215) 963-5377

December 27, 1985

RECEIVED
DEC 30 1985
SECRETARY'S OFFICE
Public Utility Commission

Jerry Rich, Secretary
Pennsylvania Public Utility
Commission
North Office Building
Commonwealth and North Streets
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v.
Philadelphia Electric Company
Docket No. R-850152

Dear Secretary Rich:

Enclosed for filing are an original and two copies each of a Protective Agreement dated November 1, 1985 relating to Interrogatory Request IR-OCA-II-5 and 7 and a Protective Agreement dated December 6, 1985 relating to Interrogatory Request IR-OCA-III-2 in the above-captioned proceeding.

By the enclosed Certificate of Service I certify that I am this day serving copies of the enclosed two Protective Agreements dated November 1, 1985 and December 6, 1985, respectively.

Sincerely,

Frederick H. Knight, 3rd

ddq
Enclosure

DOCUMENT
FOLDER

CERTIFICATE OF SERVICE

I hereby certify that copies each of a Protective Agreement dated November 1, 1985 relating to Interrogatory Request IR-OCA-II-5 and 7 and a Protective Agreement dated December 6, 1985 relating to Interrogatory Request IR-OCA-III-2 were served by first class mail, postage prepaid on all active parties on December 27, 1985 in the Limerick I Rate Proceeding at Docket No. R-850152.

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
New Filing Section
Secretary's Bureau, Room B-18
North Office Building
Commonwealth and North Streets
Harrisburg, PA 17120

John Hanger, Esquire
Community Legal Services, Energy Project
3638 North Broad Street
Philadelphia, PA 19140

David M. Kleppinger, Esquire
100 Pine Street
Harrisburg, PA 17120

Zori G. Ferkin, Esquire
Governor's Energy Council
P.O. Box 8010
300 N. 2nd Street
Harrisburg, PA 17105

Scott Rubin, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

Mildred E. V. Pitts, Esquire
Information Resources & Utilities Division
General Services Administration
Room 4002
18th and F Streets, N.W.
Washington, DC 20405

Charles E. Rainey, Jr., Esquire
Municipal Services Building
Law Department, 15th Floor
Philadelphia, PA 19102

Edward S. Wardell, Esquire
Constance B. Foster, Esquire
Dilworth, Paxson, Kalish & Kaufman
2600 The Fidelity Building
Philadelphia, PA 19109-1094

Nancy Schuster, Esquire
1 Pond Street
Bristol, PA 19007

Patricia M. Gustin
Pennsylvania Public Utility Commission
Room G-33
North Office Building
Harrisburg, PA 17108

Earle H. O'Donnell, Esquire
Merrill L. Kramer, Esquire
Sutherland, Asbill & Brennan
1666 K Street, N.W.
Washington, D.C. 20006-2803

Mark P. Widoff, Esquire
Widoff, Reager, Selkowitz & Adler
129 State Street
Harrisburg, PA 17101

Michael Browne, Esquire
Reed, Smith, Shaw & McClay
1600 Avenue of the Arts Building
Broad and Chestnut Streets
Philadelphia, PA 19107

Honorable Joseph P. Matuschak
Pittsburgh State Office Building
300 Liberty Avenue
Pittsburgh, PA 15222

Wayne L. Emery, Esquire
Kenneth R. Pepperney, Esquire
Rafael Caminero, Esquire
600 Grant Street, Rm. 1580
Pittsburgh, PA 15230

Alan R. Squires, Esquire
Greenstein, Gorelick, Price,
Silverman & Laveson
900 Two Penn Center Plaza
Philadelphia, PA 19102

Anthony G. Tummarello
Director of Energy
Occidental Chemical Corporation
P.O. Box 4020
River Park
Darien, CT 06820

Frederick H. Knight
Counsel for Philadelphia
Electric Company

RECEIVED

DEC 30 1985

SECRETARY'S OFFICE
Public Utility Commission

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

PROTECTIVE AGREEMENT

The Pennsylvania Office of Consumer Advocate ("OCA") and its consultants Whitfield A. Russell & Associates, and Philadelphia Electric Company ("PECO") hereby agree that the information and data being provided for inspection in response to Interrogatory Request IR-OCA-3-2 in the above-captioned proceeding are considered by PECO to be confidential and proprietary. PECO is willing to provide this material to the OCA and its consultants Whitfield A. Russell & Associates subject to certain conditions necessary to preserve its confidential and proprietary nature.

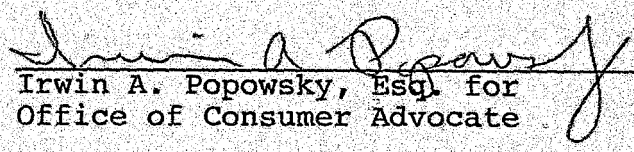
The OCA and Whitfield A. Russell & Associates hereby agree that any documents or information obtained during the course of their review will be kept confidential and will not be disclosed to any person outside the OCA and Whitfield A. Russell & Associates and will not be disclosed to any person

DOCKETED
JAN 2 - 1986

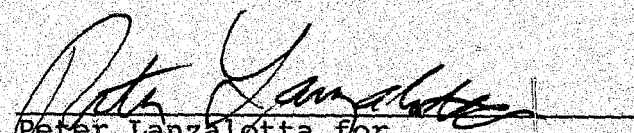
not directly involved in the OCA and Whitfield A. Russell & Associates' review of these documents. The OCA and Whitfield A. Russell & Associates further agree that the information and documents obtained during their review will not be used for any purpose other than in the above-captioned proceeding, and that all copies of documents obtained during their review, which are not ultimately included in the record in this proceeding, will be returned to the Company upon final resolution of this matter.

The OCA and Whitfield A. Russell & Associates also agree to explore all reasonable alternatives to placing any confidential or proprietary information or documents obtained during their review in the public record, and will provide the Company prior notice and opportunity to object before the material is so used. Finally, if confidential or proprietary information is to be made a part of the public record or otherwise disclosed outside of the OCA and Whitfield A. Russell & Associates, the parties agree to develop appropriate procedures to protect fully the confidentiality and proprietary nature of the information and documents provided to the OCA and Whitfield A. Russell & Associates.

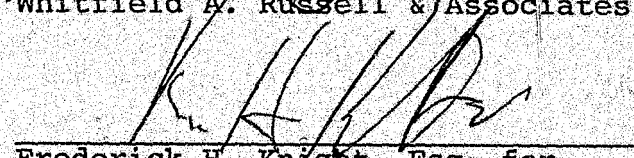
Intending to be legal bound hereby, the parties have hereunder executed this Agreement.



Irwin A. Popowsky, Esq. for
Office of Consumer Advocate



Peter Lanzalotta for
Whitfield A. Russell & Associates



Frederick H. Knight, Esq. for
Philadelphia Electric Company

DATED: December 6, 1985

RECEIVED
DEC 20 1985
SECRETARY'S OFFICE
Public Utility Commission

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

PROTECTIVE AGREEMENT

The Pennsylvania Office of Consumer Advocate ("OCA") and its consultants Komanoff Energy Associates, and Philadelphia Electric Company ("PECO") and its consultants National Economic Research Associates ("NERA") hereby agree that that the information and data listed below are considered by NERA to be confidential and proprietary. NERA is willing to provide this material to the OCA and its consultants Komanoff Energy Associates in the above-docketed proceeding subject to certain conditions necessary to preserve its confidential and proprietary nature. The information and data were requested by the OCA in Questions 5 and 7 of Set II of the OCA's Interrogatories to PECO in the above-docketed proceeding.

The OCA and Komanoff Energy Associates agree that their employees, agents, contractors and representatives will utilize the information and data produced pursuant to this Agreement for the sole purpose of analyzing the position of PECO in the above-docketed proceeding. The OCA and Komanoff Energy Associates agree that they will not make copies in any form, use in any other proceeding, disclose to any other person, including

DOCKET FOLDER

DOCKETED
JAN2-1985

other parties to this proceeding, use or make publicly or privately available to any third party the information and data produced pursuant to this Agreement. The OCA and Komanoff Associates further agree that they will not include any information or data produced pursuant to this Agreement in the direct testimony of OCA witnesses in the subject proceeding without the specific written consent of NERA having been first obtained and will not enter the information and data subject to this Agreement or any part thereof into the public record. The OCA and Komanoff Energy Associates also agree that they will return all copies of the information and data described herein, and any analyses prepared utilizing such information and data, to NERA within thirty (30) days after the close of the record in this proceeding.

Intending to be legal bound hereby, the parties have hereunder executed this Agreement.

The information and data whose proprietary and confidential character are recognized and preserved in this Agreement are as follows:

NERA data base referred to in Questions 5 and 7 and Answers thereto of Set II of the OCA's Interrogatories to PECO.

Scott J. Rubin, Esq. for
Office of Consumer Advocate

Charles Komanoff, for
Komanoff Energy Associates

Frederick H. Knight, Esq. for
Philadelphia Electric Company

Lewis J. Perl
National Economic Research
Associates

Dated: November /, 1985

RECEIVED

DEC 30 1985

SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

Direct Testimony of

Joseph W. Gallagher

DOCKETED

JAN 2 - 1986

Concerning

Response to ECR No. 8
Order, Appendix B, Item 4

DOCUMENT FOLDER

December 30, 1985

PECO Statement No. 30
Docket No. R-850152

TESTIMONY OF JOSEPH W. GALLAGHER

Q: Please state your name and business address.

A: Joseph W. Gallagher, 2301 Market St., Philadelphia, PA.

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

A: I am employed by the Philadelphia Electric Company and, since January 1984, I have served as Manager of the Engineering and Research Department. For six years prior, I was Manager of the Electric Production Department.

Q: What is your educational background?

A: I graduated from Villanova University in 1949 with a degree of Bachelor of Electrical Engineering. In 1967, I completed the Executive Development Program at Cornell University and have taken graduate courses at Northwestern and Drexel Universities.

Q: What are your professional affiliations?

A: I am a licensed professional engineer in Pennsylvania, License #02358E. I was a member of the Operating Committee of the Pennsylvania, New Jersey, Maryland ("PJM") Interconnection for eleven years and was a member of the North American Power Systems Interconnection Committee for four years. I have served on the U.S.-U.S.S.R. Committee on Power System Planning and Operation since 1974 and also

serve on the Prime Movers Committee of the Edison Electric Institute, which is concerned with power generation matters. I am also a senior member of the Institute of Electrical and Electronics Engineers and have served on several technical committees of that organization.

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

A: I started with Philadelphia Electric in 1950 as an electrical engineer in the System Planning Division where I worked for approximately 12 years. My duties included planning of the distribution system and the generation and transmission systems and, later, supervision of the long-range generation and transmission branch. After that, I was assigned to the General Administration Department as a staff engineer for about six and one-half years. I was promoted to Assistant Superintendent of the System Operation Division in the Electric Production Department where I worked for five years and was then promoted to Superintendent in the same division for three years. During that time, I was responsible for scheduling production at Philadelphia Electric plants, assuring that they were on-line when needed, directing the load at which the plants were being operated, coordinating plant maintenance and releasing equipment for maintenance, directing the switching and blocking on the transmission system; monitoring transmission

line loadings, coordinating generation and transmission outages, and managing service restoration. I served as General Superintendent of the Maintenance Division for one year before being promoted to Manager of the Electric Production Department in April, 1978. My responsibilities, as General Superintendent of Maintenance, included management of the maintenance program of all generating stations, substations, and steam heating system facilities on the Philadelphia Electric Company system.

Q: Please briefly describe the Engineering and Research Department and your responsibilities as Manager of that Department.

A: The Engineering and Research Department is responsible for the planning, engineering, design and construction of all new facilities of the Philadelphia Electric Company. It is responsible for capital modifications of all facilities, load estimating, system planning, and research projects, also. As Manager of the Engineering and Research Department, I administer all of the functions of the Department, subject to the direction and supervision of the Vice President, Engineering and Research. In addition, I review the budgets and cost control systems for all capital work at all facilities, including those partially owned by Philadelphia Electric, but not operated by the Company.

Q: Previously you indicated that, prior to January, 1984, you were the manager of the Electric Production Department. Please briefly describe the Electric Production Department and the responsibilities you had in your prior position as Manager of that Department.

A: The Electric Production Department operates and maintains all of the electrical production facilities operated by Philadelphia Electric, including the Company's nuclear, coal, oil and hydroelectric facilities. It also operates and maintains the Company's steam heating supply stations. The Department is responsible for maintenance work on all generation and supply equipment under Philadelphia Electric's control and coordinates the Company's operations with the PJM Interconnection. As Manager of the Electric Production Department, I administered all of the functions of the Department, subject to the direction and supervision of the Vice President, Electric Production. In addition, I reviewed the operations, budgets, and cost control systems for the electrical production facilities including those partially owned by Philadelphia Electric, but not operated by the Company. These include the Salem nuclear plant, which is operated by Public Service Electric & Gas Company and two coal-fired generating stations (Keystone and Conemaugh) operated by Pennsylvania Electric Company.

Thus, in my positions as the former Manager of the Electric Production Department and now as Manager of the Engineering and Research Department I have had responsibility for, and exercised oversight of, the planning, engineering and implementation of both capital modifications and maintenance work. As I will explain below, these two categories -- capital modifications and maintenance work -- represent the classifications into which all major improvement projects at generating stations are divided for cost approval and implementation purposes.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain improvements Philadelphia Electric Company has made or intends to make in the near future to its baseload generating units to enhance their performance. This information is provided to comply with the following data requirements which are contained in Appendix B to the Pennsylvania Public Utility Commission's Order entered October 30, 1985 at Docket Nos. P-830453, M-840375 and M-FACE8408:

> "The following information and data shall be supplied by the Company ...
>
> (4) Generating Unit Performance Improvements
>
> (i) A report detailing all Company efforts designed to improve system generating efficiency ..."

The Order further explained this data requirement by stating that the information to be provided should focus upon

"Prudent and projected generating unit performance improvements planned or anticipated by the Company."

I also explain major procedure-oriented and personnel-oriented changes and programs as well as capital and maintenance improvements that can have a positive effect on baseload generating performance. I also describe generally the processes and procedures employed by the Company to identify, authorize and implement capital modifications and maintenance work.

I have provided information principally with regard to baseload units. These consist of nuclear units (Peach Bottom 2 and 3 and Salem 1 and 2), the Philadelphia-Area coal-fired units (Eddystone 1 and 2 and Cromby 1), and the mine-mouth coal-fired units (Keystone 1 and 2 and Conemaugh 1 and 2). I should mention that, while the Philadelphia-Area coal-fired units have been categorized as baseload units, they are used by the Company for load-following at times.

Of course, the Company also has oil-fired units, combustion turbines and hydroelectric capacity. However, I have presented information principally for nuclear and coal-fired baseload units because, due to the duration of their operation throughout a year and relatively lower energy costs, "performance improvements" in these units generally have a greater effect on system energy costs.

For purposes of the information I have provided, I interpreted the criteria "system generating efficiency" and "unit performance improvements" as encompassing, in the case of nuclear units, unit availability and, in the case of coal-fired units, unit availability and thermal efficiency. By thermal efficiency, I mean net unit output relative to the fuel input.

Q: Explain how capital modifications and needed maintenance at generating stations is identified, authorized and implemented.

A: As I previously described, the Company's Electric Production Department is responsible for the operation and maintenance of all the Company-operated generating facilities. The Superintendent and Assistant Superintendent at each station, who are typically referred to as "Station Management", are members of that Department. Station Management originates requests for investigation of systems or components that either have failed or are exhibiting what station personnel consider to be deteriorated or unsatisfactory performance. Such investigations are conducted by the Engineering and Research Department's Mechanical or Electrical Engineering Divisions, with input from station personnel or other divisions of the Electric Production Department, as required or deemed desirable. Such investigation is directed to establish the probable cause of the identified failure or

unsatisfactory performance, to develop the necessary plan for fixing or improving the system or component studied, to estimate the costs to implement the fix, to make necessary cost-benefit analyses to determine if implementing the design fix is cost-justified and will provide an overall "economic" benefit, and to make a recommendation to Station Management.

If the recommendation is to proceed with the work identified as necessary and cost-justified, Station Management makes a request for authorization to expend funds for the project. If the work entails a capital modification, a Capital Authorization or "CA" is requested. If the necessary work represents maintenance, an Expense Authorization or "EA" is requested. PECO management reviews and approves the requested CAs and EAs, the expenditures for which must be integrated into PECO's overall capital and operating budgets.

After a CA or EA is approved, implementation requires completion of final engineering, scheduling (work that can be done only when a unit is shut down must be fit into the schedule for planned outages), procurement of necessary materials, and preparation of specifications and requests for bids or proposals if outside contractors are to be used.

Work authorized by a CA is implemented by the Engineering and Research Department's Construction Division,

and work authorized by an EA is implemented by the Maintenance Division of the Electric Production Department. However, engineering design and technical supervision is provided, in both cases, by the Engineering and Research Department.

Q: What is the Company's participation in the process of authorizing capital and maintenance work at jointly-owned plants that are operated by a joint-owner other than PECO?

A: For jointly-owned plants operated by others, PECO participates in the work review and approval process at the level of the owners' groups, consisting of representatives of each utility having an ownership share in the plant. The operating utilities have procedures similar to PECO's for identifying, analyzing, cost-justifying and approving capital and maintenance work. The strategic decisions for major capital or maintenance programs are submitted to the owners' group for review and approval.

Q: Please describe the information you are submitting in response to the data requirements of the Commission's October 30, 1985 Order.

A: The information is set forth in Schedules 1 and 2 attached to this Statement. Each Schedule corresponds to the categorization of work projects I identified before. That is, Schedule 1 lists capital modifications and Schedule 2 lists maintenance projects. Additionally, Schedule 2

describes personnel-oriented and procedure-oriented changes that are intended or expected to have a beneficial effect on unit performance.

Q: Please refer to Schedule 1 and explain what it shows.

A: Schedule 1 consists of five tables, each containing information about one or more units, as follows:

Table 1	Eddystone 1 and 2
Table 2	Cromby 1
Table 3	Peach Bottom 2 and 3
Table 4	Salem 1 and 2
Table 5	Keystone 1 and 2 and Conemaugh 1 and 2

Each Table shows, for the units it comprehends, capital modifications that will have a positive impact on unit performance. The modifications have been broken out among those completed within the last three years and those projected for substantial completion within the three-year period ending in 1988. Some of the projected work is already in progress.

The first column identifies the project, the second column shows the approximate cost, the third column indicates the area of performance anticipated to be enhanced (availability and/or efficiency), and the last column provides additional information explaining the need for or likely benefit of the work.

I should note that, because the number of modifications for each unit is voluminous, I have shown only those that exceeded or are anticipated to exceed $1 million.

Some of the projects listed were necessitated for environmental, safety-related, or regulatory compliance. However, the work was included on the schedule because, if not done, the performance of the unit would have been adversely affected. Thus, for example, RHR and recirculation pipe replacement at Peach Bottom 2 was necessitated by safety-related concerns associated with the generic problem of Intergranular Stress Conosion Cracking in large-bore piping of Boiling Water Reactors, which was present at Peach Bottom. By replacing the piping with non-susceptible material and by using longer spool lengths -- thereby reducing the number of welds -- a potential future reduction in inspections could be expected, which should reduce outage time, reduce the risk of shut-downs due to IGSCC-related problems, and exert a positive effect on future availability. Similarly, changes in SO2 scrubbers at the Philadelphia Area Coal plants have the potential to reduce the duration of shut-downs to comply with environmental standards.

Q: Please refer to Schedule 2 and explain what it shows.

A: Schedule 2 consists of two parts. Part I contains a description of major maintenance work in progress or scheduled for completion within approximately three years that is expected to have a positive effect on unit performance. In lieu of itemization of work packages, to

which the maintenance work does not readily lend itself, a brief narrative description of the work to be performed on a system or component is provided.

Part II contains, also, a brief description of major procedure-oriented and personnel-oriented programs implemented by the Company that are expected to enhance or avoid deterioration of unit performance by reducing outage time or that are expected to reduce the cost of operation and maintenance by permitting needed work to be done in a more time and/or cost efficient manner.

Q. Please provide an overview of significant planned improvements affecting performance at the Company's coal and nuclear plants which are intended to address major contributors to unit unavailability.

A. For Peach Bottom, such significant planned improvements include refueling platform replacements and increasing the capacity of the spent fuel rack -- which should improve refueling performance, replacing the feedwater heater, replacing the low pressure turbine rotors on Peach Bottom 3 (rotors in Peach Bottom 2 were replaced during the outage which ended in July, 1985), and replacement of recirculation and RHR piping in Peach Bottom 3. More detail as to the effect of these improvements is set forth in Schedule 1, Table 3.

For Salem, such significant planned improvements include various pump improvements and replacements, heat exchangers' modifications, and major control and instrumentation modifications, as detailed in Schedule 1, Table 4.

For the Philadelphia-area coal plants such significant planned improvements include, at Cromby 1, replacing the low pressure rotor, modifications to the fly ash disposal system, and installation of micro-processor-based controls, and, at Eddystone, replacing the feedwater heaters at Unit 2, completion of the comprehensive boiler rehabilitation program at Unit 2, installation of micro-processor-based controls at both units, and implementation of computer analysis to identify availability impacting problems with the SO2 scrubbers on both units. More detail as to these items is set forth in Schedule 1, Tables 1 and 2.

For the mine-month coal plants, such significant improvements include, at Keystone, replacing economizers, balanced draft conversion, and replacing low pressure feedwater heaters, and, at Conenaugh, replacing the low pressure and high pressure feedwater heaters, replacing air preheater coils, and obtaining spare low and intermediate pressure turbine rotors. In addition, major replacements and modifications of steam generator components (casings, ductwork and pressure vessels) have been in progress and are

continuing. These and additional items are explained in Table 1, Schedule 5.

Q. In addition to the specific equipment-based projects you have described, please describe PECO's preventive maintenance program.

A. PECO has in place an extensive preventive maintenance program applicable to all of its generating stations. For example, during each legally-mandated boiler inspection, the boiler is extensively inspected both visually and by non-destructive testing to detect and correct developing problems that could result in forced outages or decreased capacity. Each major steam turbine-generator is totally inspected over a six-year cycle, on a component-per-year basis. All unit generators, major electric motors, and transformers are inspected and subjected to electrical testing on a periodic basis to detect incipient failures. Periodic inspections and overhauls of all major auxiliary systems are made on schedules reflecting the Company's experience in maintaining central generating station equipment. The goal is to reduce the forced outage rate to the maximum feasible and cost-effective extent, considering resource limitations, and to reduce scheduled outages to a minimum cost-effective duration and frequency.

Q. Explain the general principles and criteria that guide PECO's approach to making "unit performance improvements".

A. PECO's general approach is to implement practicable capital or maintenance projects and programs that, based on appropriate analysis and engineering judgment, are reasonably projected to result in overall economic benefit. The pursuit solely of the highest standard of unit performance to the exclusion of other concerns can produce uneconomic results. That is, the capital and maintenance costs incurred to achieve an incremental increase in operating performance can exceed the marginal reduction in energy costs they might produce. In short, work to be done solely to achieve increased unit performance must be cost-justified on the basis of total costs.

These principles are taken into account by PECO in the work authorization procedures I explained before. Specifically work -- other than that mandated by regulatory requirements or health and safety concerns -- is analyzed on a cost benefit basis before expenditures are authorized. The cost-benefit analysis can be more or less formal or sophisticated depending upon the nature, scope and total cost of the work. In some cases, the cost-benefit is clearly justified or unjustified without substantial, written analyses.

Q. Can you explain briefly the quantifiable effects on unit performance of unit improvements and modifications.

A. The effects on total unit performance are difficult to quantify, because unit performance is a function of the dynamic interaction of numerous complex engineering systems. There is one important factor to be remembered, however. Improvements in the performance of a given system or component are not translated into improvements in total unit performance of equal magnitude. Thus, if problems in a given system or component contributed 2 percentage points to the unit's total forced outage rate, correcting those problems will not result in a 2 percentage point reduction in the forced outage rate. The improvement in unit forced outage rate is, generally, less than the improvement in the system's or component's performance. Moreover, as a unit ages and new problems arise, no absolute improvement in performance from past capital modifications and maintenance activities may occur. Rather, capital modifications and maintenance achieve a continuation of existing performance levels or of levels above those that would otherwise be obtained absent those efforts.

Q. Does this conclude your statement?

A. Yes, it does.

TABLE 1

EDDYSTONE UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Rotor stress indicators		A	Guide to operator to prevent misoperation that ultimately would result in shortened turbine life
Cold reheat water induction protection system (Unit 2)		A	same as above
Chlorine injection modifications		A/E	Prevents organic contamination of condensor--thus improving efficiency--while complying with stricter environmental regulations
Electrostatic precipitator rappers		A/E	Replace and upgrade rappers; reduces particulate scrubbing
Water discharge system modifications		A/E	Improvements to turbine bypass reduces start-up time, improve availability and reduces start-up fuel
Auxilliary steam back-up		A/E	Improvements that shorten start-up time, improve availability and reduce start-up fuel
Fire protection modifications		A	Localizes and minimizes damage in the event of a fire, thereb reducing possibility of long forced outage due to fire and resulting damage
SO_2/particulate scrubbers	147,430	A	The only alternatives to compl with the Clean Air Act were to retire the unit or convert the units to oil. Installation of scrubbers was the most economi cal choice to retain that capacity.

TABLE 1

EDDYSTONE UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Replace main steam piping (Unit 1)	8,575	A	Piping was at the end of life; in order to retain this unit's capacity, piping had to be replaced.
Coal pile runoff system	1,650	A	Due to environment law requirements, if this system were not added, the plant would have to be retired or converted to oil.
Turbine stop and control valves	6,420	A	Same as MSP replacement
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace superheater outlet headers (Unit 1)	4,110	A	Material at end of life; to retain this capacity, replacement required.
Develop and implement program to assess high pressure piping integrity		A	To identify possible incipient problems so that effective planning can be developed and repair or replacement coordinated with scheduled outages
Wastewater treatment modifications	1,046	A	To avoid breakdowns that result in environmental violations requiring shutdowns
Feedwater, steam temperature, CC, PD and H.P. boilerfeed pump controls	1,790	A/E	Initial phase of long-term program to upgrade major control systems using microprocessor distributed system technology. To maintain steam pressure and temperature within design parameters. Shortens start-up time and improves thermal performance

TABLE 1

EDDYSTONE UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Water induction protection (Units 1 and 2)		A	Expanded application of water induction protection explained before
Soot blower control panel replacement		A/E	Replacement and upgrade to allow closer control of steam temperature
ATC (combustion air) drive and control replacement		A/E	Replace and upgrade. Provides more efficient burning of fuel by giving operator control of combustion air
Auxilliary boilers (convert from No. 6 fuel oil to gas firing)	1,500	A/E	Increases availability (because lower maintenance) and improves efficiency
Replace igniters (Units 1 and 2)	1,000	A/E	Reduces start-up time, reduces start-up fuel, increases availability
Replace air tempering coils		A/E	Improves thermal performance
Replace feedwater heaters (Unit 2)	2,135	A/E	Recoup availability and thermal efficiency lost due to tube failures
Air dryers		A	Reduces moisture in compressed air-powered controls; avoids freeze-up
Vibration monitoring		A	Upgrade monitoring of rotating equipment to avoid in-service failures

TABLE 2

CROMBY UNIT 1

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
SO_2/particulate scrubbers	77,032	A	(see explanation of similar item in Table 1)
Replace ignitors		A/E	(see explanation of similar item in Table 1)
Replace economizer		A/E	Improves availability; avoids forced outage due to tube failures
Bag house by-pass duct		A	Allows operation while bag-house is out of service
Replace No. 4 feedwater heater		A/E	(see explanation of similar item in Table 1)
Feedwater, steam temperature, CC controls		A/E	(see explanation of similar item in Table 1)
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Chlorine injection system		A/E	(see explanation of similar item in Table 1)
Demineralizer regeneration pump suction modifications		A	Pump modification to reduce in-service failures
Fire protection modifications		A	(see explanation of similar item in Table 1)
Coal pile run-off system		A	(see explanation of similar item in Table 1)
Purchase of replacement L.P. rotor		A/E	Permits replacement during scheduled outage; updated blade design

TABLE 3

PEACH BOTTOM UNITS 2 AND 3

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Off-gas system improvements	6,526	A	Installation of separators, drains and vents to improve moisture removal; increase reliability and reduce maintenance
Rod-waste storage facility	6,100	A	Increase storage.
Recombiner upgrade		A	Eliminated need for pressurized hold-up and compression; increases reliability and decreases maintenance.
Main steam drain valves		A	Facilitates moisture removal from main stream lines; reduces risk of damage to turbine.
Plant simulator	1,800	A	Used for operator training; increases efficiency of operation and has potential to reduce down-time due to operator error.
Replace recirculation and RHR piping (Unit 2)	31,100	A	Replacement with nonsusceptible material and longer spool pieces; reduces ISI and future IGSCC problems.
Replace safe ends (Unit 2)	4,840	A	Replacement with nonsusceptible material; reduces future IGSCC problems.

TABLE 3

PEACH BOTTOM UNITS 2 AND 3

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace L.P. turbine rotors (Unit 3)	2,970	A	Improve future reliability, reduce maintenance; restore performance capability.
Reactor feed pumpts recirculation valves		A	
Refueling platform modifications		A	
Increase capacity of spent fuel racts	3,830	A	Increases number of cycles of operation with existing spent fuel pool.
Install new recirculation and RHR piping (Unit 3)	30,170	A	(See the explanation of similar item for Unit 2).
Replace L.P. turbine rotors (Unit 2)	2,150	A	(See the explanation of similar item for Unit 3).
Replace feedwater heaters		A	(See explanation of similar item in Table).
Control room and instrumentation modifications		A	Partially NRC-required; increases operating efficiency.

TABLE 4

SALEM UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) (s)	Reason and Effect on Performance A = Availability E)= Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Rewind generator (Unit 1)	2,252	A	Generator failed; rewind increases reliability and availability.
Replace generator (Unit 2)	10,350	A	Generator failed, replacement necessary to restore unit availability; increases reliability.
Upgrade moisture separator reheater shells	2,428	A	Improves moisture removal; reduces risk of damage to turbine.
Condensate pump mod. (Unit 2)	1,313	A	Increase reliability, reduces maintenance and increases cycle efficiency.
Retube component cooling heat exchanger		A	Experiencing numerous tube failures; retubing increases reliability and availability.
Upgrade circulating water screen wash.		A	Improves operation and reduces maintenance.
Upgrade H.P. feedwater heater internals		A	Experiencing failures and degraded performance; internal upgrade increases reliability and performance.

TABLE 4

SALEM UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Reactor coolant pump motor resistance rings		A	Improve availability, reduce maintenance.
Replace turbine by-pass steam valves		A	Reduces start-up time; improves availability.
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace moisture separator tube bundles	5,473	A	(See the explanation for MSR shell replacement).
Replace RHR sump pumps		A	Old pumps were experiencing high level of failures affectin availability.
Upgrade circulating water pump leaving lubrication pump		A	Improved bearing cooling capability which had become a high maintenance item.
Reactor vessel head quick disconnect tensioner		A	Facilitates head removal; reduces outage time.
Replace service water strainer		A	Existing strainer experiencing high maintenance and poor availability due to corrosion.

TABLE 4

SALEM UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace chiller condensers		A	Existing condensers experienci high rate of tube failures; replaces increases reliability and performance
Replace primary system flow transmitters		A	Existing transmitters were hig maintenance items and spare parts not available; replaceme increases reliability and performance.
Replace turbine area sump pumps		A	Old pumps experiencing failure affecting availability.
Upgrade plant simulator		A	(See explanation of similar item in Table 3).
Upgrade circulating water pump internals		A	High maintenance and effect on availability; upgrade increase reliability.
Replace service water piping to component cooling heat exchanger		A	High maintenance item -- leaks and failures -- operating availability; upgrade increase reliability.
Turbine-generator suspension instrumentation		A	Temperature and vibration monitoring; identifies incipie problems; avoids failures, reduces trips during start-up.

TABLE 5

KEYSTONE UNITS 1 AND 2
CONEMAUGH UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
(Keystone)			
Turbine water induction protection modifications		A	Guide to operator to prevent misoperation that ultimately could result in shortened turbine life
Develop East Valley ash and coal refuse disposal site	1,520	A	Adequate, environmentally-approved waste disposal site required for continued operation
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
(Keystone)			
Replace economizers	4,000	A/E	(see explanation of similar item in Table 2)
Convert boilers to balanced draft	10,745	A/E	Increase availability by reducing casing leaks and hot spots
Replace station computers	1,880	E	To monitor operating parameters and highlight losses that can be corrected
Develop additional ash disposal sites		A	(see similar item explained above)
Electrostatic precipator modification		E	Improve collecting efficiency; avoids load reductions due to air pollution violations
Replace L.P. feedwater heaters		A/E	(see explanation of similar item in Table 1)
Purchase spare boiler circulating pump		A	Long lead time item; purchased in advance for orderly integration of repair/replacement in scheduled outage and less down-time in event of in-service failure

TABLE 5

KEYSTONE UNITS 1 AND 2
CONEMAUGH UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Wastewater treatment system improvements		A	(see explanation of similar item in Table 1)
Purchase spare boiler feed pump coupling elements		A	Reduce risk of extended outage due to in-service failure or inspection that discovers problem. Long lead-time for procurement.
(Conemaugh)			
Replace H.P. and L.P. Feedwater heaters	1,312	A/E	(see explanation of similar item in Table 1)
Replace station computers	1,852	E	(see explanation of similar item for Keystone)
Develop additional ash disposal sites	1,140	A	(see explanation of similar item for Keystone)
Electrostatic precipitator gas flow improvements		A	(see explanation of similar item for Keystone)
Purchase spare boiler circulating pump		A	(see explanation for similar item for Keystone)
Heat rate monitoring equipment		E	Adjunct to computers and extension of their capabilities

Statement 28A

RECEIVED
DEC 30 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

Supplemental
Direct Testimony

of

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

DOCKETED
JAN 2 - 1985

Concerning

The Energy Cost Rate

DOCUMENT

Q. ARE YOU THE SAME JOSEPH F. BRENNAN WHO OFFERED RATE OF RETURN TESTIMONY IN THIS PROCEEDING?

A. Yes. My testimony on rate of return issues was previously admitted in evidence as PECO Statement 28. A full statement of my qualifications is provided in that testimony.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY IN THIS PROCEEDING?

A. I have been requested by Philadelphia Electric Company (PECO) to assess the likely effect upon the Company's financial position and standing in the investment community of modifying the energy cost rate (ECR) to allow reconciliation for over/under collection of only 80% of PECO's total energy costs. In preparing my testimony, I have performed a general review of the background of incentive fuel cost adjustments, and I have assessed the likely financial impact of the proposal made specifically for PECO on the financial integrity of the Company.

Q. HAVE YOU PREPARED AN EXHIBIT TO ACCOMPANY THIS SUPPLEMENTAL TESTIMONY?

A. Yes. Exhibit JFB-2, comprised of 6 Schedules.

Q. DOES THE PRESENCE OR ABSENCE OF A MECHANISM TO ALLOW FULL AND TIMELY RECOVERY OF FUEL COSTS HAVE AN EFFECT ON THE PERCEPTION OF AN ELECTRIC UTILITY'S RISK?

A. Yes. Automatic fuel cost adjustment mechanisms such as the ECR are a key factor in stabilizing the variation in an electric utility's earnings and rate of return, and hence, investor perception of risk. Variations in earnings and rate of return can make the difference between rating grades with respect to long-term debt, keeping in

Associated Utility Services, Inc.

mind the fact that earnings on equity provide the margin by which fixed charges are earned more than once, and the difference between stocks selling at or below book value. To the extent that fuel costs are not recovered in a timely manner, swings in earnings wider than otherwise may occur to the point of an investor perception of increased business risk. Moreover, to the extent that rising fuel costs are not fully recovered, there may be a deterioration in a utility's earned rate of return, which can cause downgradings of long-term debt, falling stock prices, and resultant higher cost of capital ultimately reflected in the price of service to the detriment of all, including consumers. Such factors are precisely the situation that led to the institution of energy adjustment clauses in the 1960's. The combination of general inflation and rapid inflation in fuel costs beyond the control of utilities had impaired seriously the financial integrity of many utilities. In periods of increasing fuel costs, utilities' cash flows were strained as the gap between incurred and recovered costs widened. The ECR was designed not to provide additional revenues to the Company but to provide stability in cash flow and earnings so as to mitigate against the increasing riskiness of utilities because of rising and fluctuating fuel costs.

In essence, there has been an implicit compact between utility investors, customers, and regulators. Investors receive no loss or benefit from changes in fuel costs. In turn, they receive prompt payment for expenses incurred for any fuel or purchased power costs. Customers benefit by a lower price of service than otherwise in the form of a lower cost of capital. This lower cost of capital is ob-

tained from a more predictable and dependable level of income and reflected in the price of service.

Q. MR. BRENNAN, IS THERE ANY DIRECT EVIDENCE THAT RATINGS AGENCIES, AND THE INVESTMENT COMMUNITY GENERALLY, CONSIDER THE PRESENCE OF AN ADEQUATE AND FAIR FUEL ADJUSTMENT CLAUSE AN IMPORTANT FACTOR INFLUENCING RISK AND RATINGS?

A. Yes. The two major rating agencies, Moody's Investors Service (Moody's) and Standard & Poor's Corporation (S&P) monitor regulatory practices and whether credit quality is adequately protected by allowing for timely recovery of fuel and other costs.

For example, a November 11, 1978, Moody's article captures the essence of these credit concerns:

> Today, utilities face a number of uncertainties. Costs are going up, construction programs are increasingly subject to regulatory and environmental delays, load forecasting is more difficult and fuel cost as well as its supply is problematic. And these are but a few factors in the package of challenges facing the industry. There are many cost factors which are basically beyond the control of the utility, assuming it is to serve its customers adequately. Moderation of the risk borne by the investor as these cost increases squeeze profits is strictly in the hands of the regulators.
>
> As cost and risk rise, regulators must respond with higher rate approvals. If effective action is not taken, for example, to curb our nation's dependence on imported energy while concurrently producing over-all inflation, why must the utility bear the burden? If there is an increase in primary energy cost, why must the utility stand by and only hope to recover it in time? Certainly, it should expect and, indeed, deserves, an automatic adjustment for this and other significant and unavoidable expenses.
>
> Without a neutralization of risk factors through prompt and reasonable rate treatment, today's utility will be hard pressed to maintain its financial posture without a significant reduction in debt levels. While we are certainly in favor of some reduction in debt levels we also recognize that, in general, significant reductions would limit expansion capability. The only feasible solution is regulation which is sensitive to the bondholder's need as

reflected in improving earnings protection and cash flow. Some state commissions are probing successfully in their efforts to strike the correct regulatory balance while some others do not seem to be aware of the problem. Ratings must reflect the differences.

With respect to S&P, an example of their concern is their June 1982 response to a Michigan legislative initiative which would have, among other things, abolished all rate adjustment mechanisms. S&P responded by placing most utilities in Michigan on their watch list for potential rating changes. In its discussion of the Michigan legislative initiative, S&P stated:

> The initiative's negative impact on credit quality would likely range from moderate for telephone companies to major for the gas and electric utilities. At a minimum, the risks of under recovery of increases in operating costs would appear to be substantial. Primarily affected are purchased gas, the largest expense item for gas distributors, and fuel costs for electric generation, the highest expense for electric utilities. Automatic gas fuel, and purchased power adjustment clauses have long been in effect in virtually all states and are very significant in the process of matching revenues with expenses. These rapid energy cost recovery mechanisms are regarded as critical elements of earnings stability for gas and electric utilities.

Q. CAN YOU CITE ANY OTHER INSTANCE OF RATING AGENCY CONCERN WITH RESPECT TO A FUEL ADJUSTMENT CLAUSE?

A. Yes. In 1980, the Missouri Supreme Court ruled that fuel adjustment clauses were unlawful. As a result, the Missouri Public Service Commission eliminated the fuel adjustment clause, and this partly contributed to S&P's downgrading of Missouri Power & Light's debt rating to "BBB" from "A-." In its rationale, which was published on August 2, 1980, S&P stated: "While capital pressures can generally be regarded as manageable, regulatory actions have not provided for the adequate recovery of operating costs. Taking into account recent rate decisions by the Missouri Public Service Commission, sub-

stantial improvements in regulatory treatment will be necessary, in particular, with the elimination of the fuel adjustment clause, the need to pass-through purchase power expenses on a current basis has been heightened."

Q. WILL A CHANGE IN PECO'S EXISTING ECR BE VIEWED AS ADDING RISK TO PECO?

A. Yes, without caution and due regard for the fact that PECO's financial position at this time is quite less than robust, it is clear that a change in PECO's existing ECR will increase PECO's business risk.

Q. WHY IS PECO'S CURRENT FINANCIAL POSITION AN IMPORTANT FACTOR?

A. Prior to the advent of ECR type treatment, many electric utilities, including PECO, were quite financially healthy as evidenced by bonds of high investment grade, such as AA and AAA, and a common stock market price consistently above book value. Subsequent to the rapid and significant rise in fuel costs, bond ratings were reduced several grades to barely investment grade and a price of stock less than book value. If electric utilities had not possessed a healthy financial position at the outset, the ability to withstand the severe financial pressure of a rise in fuel costs could have led to bond ratings less than investment grade, stock prices lower than otherwise, and a cost of capital reflected in the price of service higher than otherwise. When the financial condition of the electric utility is already at the very bottom of the investment grades, a change in the ECR should be made only with the utmost care and caution.

Q. WHY IS PECO A RELATIVELY HIGH RISK ELECTRIC COMPANY?

A. In part, it is the environment in which PECO must operate. PECO is located in an area of changing economic activity. The risk that PECO is exposed to is derived from that environment. The business risk of the utility business in the Philadelphia area arises not only from the business risk of utilities generically, but also from the risk associated with the service territory. The service territory is characterized by a change-over from an industrial economic base to a service economic base. Industrial activity has been declining. One need only drive around the formerly thriving industrial areas of Philadelphia to observe the changes. Philadelphia and other areas in the Northeast find it difficult to compete for the electricity and labor intensive industries which were formerly the area's industrial base. While the electric industry in general is more risky than previously, utilities serving the major cities of the Northeast are faced with problems greater than those faced by those in the industry in general.

Q. WHAT ARE THE INDICATIONS OF PECO'S HIGH-RISK CHARACTERISTICS?

A. I discussed those in my testimony regarding fair rate of return. The most prominent is the Company's bond rating, which is Baa3 by Moody's and BBB- by Standard & Poor's. These are the lowest of investment grade bond ratings. Should bond ratings drop any further, major institutional investors under the standards of prudence will not be able to purchase PECO bonds. Electric utilities whose rating is less than investment grade have been able to sell "Junk Bonds," but "Junk Bonds" have a very limited market and related very high cost. Quite obviously, a higher cost of capital ultimately would

need to be reflected in the price of service charged to consumers. It is therefore most important that great care should be taken to not increase risk by a too severe modification in the ECR.

Q. PLEASE BRIEFLY DESCRIBE YOUR UNDERSTANDING OF THE PROPOSED CHANGES IN ECR.

A. My understanding of the proposal is derived from a review of the Commission's October 30, 1985, Order in its investigation of PECO's ECR No. 8 filing at Docket No. M-840375, et al. The proposal directs PECO to file an amended ECR rider in which only 80% of experienced over/under collections are recovered through the ECR. The remaining 20% over/under collection would not be subject to after the fact reconciliation. It has been suggested that these measures will provide an incentive to utility management to minimize fuel costs.

Q. IS IT NECESSARY TO PROVIDE ADDITIONAL INCENTIVES TO PECO'S MANAGEMENT TO STRIVE TO MINIMIZE ENERGY COSTS?

A. In my opinion, adequate incentives are already in place. This Commission has instituted a fuel audit procedure through which procurement decisions are reviewed in detail. Imprudence in fuel management practices can be detected in this process, and appropriate action can be taken. Secondly, PECO is a member of the PJM Power Pool which automatically dispatches electricity from the lowest cost source. Thirdly, prudent utility managers are cognizant of the impact of rate levels. The ECR mechanism brings nothing to net income. Higher fuel costs do not benefit the investor. They do, however, have negative economic and public relations value. Customers react to higher prices, both in terms of their attitude

toward the Company and their use of electricity. All other things being equal, customers will strive to use less energy with higher rates.

Q. ARE THERE ANY FLAWS IN AN INCENTIVE FUEL CLAUSE CONCEPT?

A. There are two obvious flaws. Without proper safeguards, there could be an investor-perceived increase in risk resulting from the implementation of an incentive fuel clause. Investors could require capital costs rates that are higher than would otherwise be the case. If investors observe regulatory caution and a legitimate possibility of higher than otherwise earnings due to the possibility of an ECR modification, there likely would be risk sharing and potentially shared benefits.

There is an inherent difficulty in accurately forecasting fuel costs. PECO has been criticized for failing to accurately forecast future energy costs, but actual fuel costs are the result of many unanticipated circumstances beyond PECO's control. Among them are forced outages, generating plant safety inspections, greater than forecasted loads which require the use of less efficient generating units, and swings in the market price of fuel. Even the most prudent management cannot anticipate or offset the effects of these unforeseeable events.

The Company has developed two sensitivity scenarios to show the impact of uncontrollable variations on fuel costs. The two scenarios and the estimated annual change in fuel and purchased power expenses as developed by PECO Witness John Carrol are:

Scenario	Annual Increase in Fuel and Interchange Expenses with an 80% ECR		
	Twelve Months Ended June 30,		
	1987	1988	1989
	(Millions of Dollars)		
Coal Scenario	108.9	137.4	136.8
Nuclear Scenario	129.4	141.3	232.2

The two sensitivity scenarios studied by PECO Witness John Carol include a coal and a nuclear scenario. The three time periods studied for each of the scenarios include estimated mid-1986-1987, estimated mid-1987-1988, and estimated mid-1988-1989.

Q. WHAT IS THE IMPACT ON INCOME AVAILABLE TO COMMON EQUITY BEFORE AND AFTER-INCOME TAXES RELATED TO AN 80% ECR REGARDING THE TWO SCENARIOS FOR THE THREE FUTURE PERIODS ON AN ESTIMATED BASIS?

A. With an 80% ECR, an approximation of the impact on net income before-income taxes ranges between $21.8 million and $46.4 million. On an after income tax basis, the estimated impact ranges between $10.9 million to $23.2 million. This information is shown on page 1 of Schedule 1.

Q. IS THERE OTHER INFORMATION SHOWN ON PAGE 1 OF SCHEDULE 1?

A. Yes. I have shown the impact of each scenario on the rate of return on common equity assuming an 80% ECR. With an 80% ECR, PECO stockholders could experience a downward movement in the rate of return on common equity after income tax ranging from 0.32% to 0.62%, or a mid-point of 0.47%. On a before income tax basis, the impact would be approximately double, given an assumed 50% income tax rate, or 0.64% to 1.24%, or a mid-point of 0.94%.

Q. HAVE YOU DEVELOPED A TABULATION TO INDICATE THE LEVEL OF FORECASTED BEFORE-INCOME TAX INTEREST COVERAGE AND ESTIMATED DETERIORATION IN THE LEVEL OF BEFORE-INCOME TAX INTEREST COVERAGE IF THE ACHIEVED RETURN RATE ON BOOK COMMON EQUITY WAS TO BE 0.62% ON AN AFTER-INCOME TAX BASIS LOWER THAN OTHERWISE?

A. Yes. That information is shown on Schedule 2. Since the opinion of bond rating agencies affects the decision of investors, as evidenced by the fact that the cost rate for long-term debt is measurably higher as lower ratings are assigned, and vice-versa, I have shown the impact inclusive and exclusive of AFC (allowance for funds). Under the new, more stringent, Standard & Poor's (S&P) coverage yardsticks published February 18, 1985, (and attached as pages 4 and 5 of Schedule 2) interest coverage for S&P bond rating purposes is calculated without regard to AFC. Further, in regard to PECO, the amount of AFC will change as a result of the rate base recognition of Limerick I and 100% of common plant.

Q. WHAT IS THE RESULT OF YOUR CALCULATIONS?

A. As can be seen by referring to page 1 of Schedule 2, the calculation with all AFC included suggests coverage of interest of long-term debt of about 3.6 times. When AFC is excluded from the calculation, the coverage falls to approximately 1.6 times. If it is assumed all Limerick I and common plant related AFC is replaced with cash earnings, the before-income tax coverage would be 3.1 times. It should be stated that to the extent something less than the rate base or expense claims of the Company relative to Limerick I and common plant was reflected in the price of service, the level of coverage excluding AFC after Limerick is in the rate base would be something

less than 3.1 times.

On page 2 of Schedule 2, I have shown identical calculations except I have also reflected the impact of the maximum calculated decline in the rate of return on common equity related to the sensitivity calculations of Company Witness John Carrol and the two scenarios and time periods previously mentioned. The calculations reflect the largest decline, or 0.62% on common equity on an after-income tax basis and 1.24% on a before-income tax basis. Please note that excluding all AFC, the basis employed by S&P with respect to developing coverage for bond rating purposes, the level of before-income tax interest coverage would be 1.5 times, which is but 0.1 times lower than produced by the calculation without regard to the sensitivity. While the impact is small, the more important point is the level of coverage before or after the impact of the sensitivity analysis. Either 1.6 or 1.5 before-income tax interest coverage is dangerously close to a level insufficient to command an investment grade bond rating. Please further note that on page 5 of Schedule 2, I have reproduced an excerpt from S&P's Credit Comment dated February 18, 1985, wherein they announce revised new (more stringent) benchmarks for electric utilities with respect to obtaining a particular bond rating. Please observe the fact that for bonds rated BBB, the very bottom of investment grades, the minimum level of coverage is 1.5 times.

Please also note on page 2 of Schedule 2 that excluding AFC related to Limerick and common plant, in other words based on the assumption that there was cash earnings replacing Limerick I and common plant related AFC, the level of coverage would be 3.0 times

after the impact of common stockholder absorption of a 0.62% impact of an 80% ECR and the most adverse of Witness John Carrol's two scenarios. Again, it should be stated that this calculation proceeds from the premise that all of the Company's rate base claim in the Limerick I rate case, again, for clarification, including all common plant, is reflected in rate base for rate making purposes and to the extent anything less is reflected in the rate base or expenses for rate making purposes, the level of coverage would be below the 3.0 times level.

For further clarification, it should be stated that these calculations proceed from an approximation of the capital structure and cost rates for long-term debt and preferred stock and a starting point estimated income level for common equity based upon the Company's budgetary June 30, 1986 income statement is evidence in this proceeding (Schedule B-8 of Exhibit TPH-2). For simplicity, I have assumed a 50% income tax rate for the purpose of these calculations.

The end result of these calculations clearly demonstrates that PECO's financial position at this time is very sub-standard. Further, any significant added risk prior to the achievement of the income level related to new service rates inclusive of Limerick I could result in PECO's bonds being rated less than investment grade. It is for this reason I urge the Commission to cautiously experiment with respect to a modification of the ECR in the best interest of consumers as well as investors. I believe this data, together with other factors I will discuss, clearly demonstrates a need for a cap on the 80% experimental ECR, at least at the outset and possibly for

a few years. A cap will serve to put on notice both investors and rating agencies that there is a regulatory intention to preclude a financial result insufficient to maintain as a bare minimum the bottom of investment grade ratings. Without the cap at the outset and an investor perception of such regulatory intentions, I believe the potential benefit of a modified ECR as proposed by the Commission may prove to be counter productive and obviously not in the public interest.

It should also be noted that there looms on the horizon other new risk factors facing investors in PECO's long-term debt and common stock. For instance, the Financial Accounting Standards Board (FASB) apparently will decide by late 1986 on a final draft of an amendment to SFAS-71. The proposed change in SFAS-71, particularly in regard to PECO, could result in investor perception of higher risk given the need to obtain timely and complete recovery of any phase-in of new plant including a return during the phase-in period. Absent adherence to the new more stringent FASB-71, writedowns could occur. Moreover, the possible change in income tax laws adds uncertainty and could also increase risk to PECO and other utilities.

Q. HAVE YOU REVIEWED INCENTIVE FUEL CLAUSES WHICH ARE CURRENTLY IN EFFECT?

A. Yes. I have studied incentive fuel clauses in two jurisdictions, California and New York. To the best of my knowledge, these two states were first to put in place incentive fuel clauses.

Q. PLEASE DESCRIBE THE INCENTIVE FUEL ADJUSTMENT CLAUSE IN USE IN CALIFORNIA.

A. California, in 1980, established for Southern California Edison Company an Annual Energy Rate (AER) and an Energy Cost Adjustment Clause (ECAC). The AER is similar to what would be called in Pennsylvania fuel recovered through base rates. From the outset the AER was set to recover 2% of estimated future variable fuel and purchased power costs and 100% of expenses related to the management of fuel oil inventory, such as carrying costs. The ECAC, which is similar to the ECR, was set to recover the remaining 98% of variable fuel and purchased power costs. This placed some risk on utility stockholders in that, if actual fuel costs were different from those that were forecast, only 98% of that variance was subject to later recovery.

That procedure was revised by the California Commission in 1982 in Decision 82-12-105, issued on December 22, 1982. This decision revised the AER/ECAC to include a 10%/90% split of variable fuel and purchase power cost. At that time the expenses related to the fuel inventory, which had been totally recovered in the AER, were also given the 10%/90% treatment. The 10%AER/90%ECAC split was characterized by the Commission as a cautious effort to increase stockholders proportion of the risk of fuel related decisions.

Furthermore, in addition to limiting the risk of non-recovery to 10% undercollections, the Commission believed that there should be a further limitation on additional risk placed on shareholders. Therefore, it established a 160 basis point cap on possible losses to stockholders. This cap is on a before-income tax basis.

Moreover, while the California Commission's actions did increase risk to investors, the California Commission also attempted

to at least partially offset risk. It is noteworthy that the Commission believed that it was reducing risk to shareholders by also including fuel inventory costs in the 10%/90% split. Previously, all of these costs had been recovered through the AER, and there was a possibility that earnings could be affected by swings in inventory related costs. In addition, it should be kept in mind that there is in California an electric revenue adjustment mechanism (ERAM) which eliminates the risk to the utility of sales swings. When sales and revenues are above or below those which were used to set the revenue requirement, the ERAM adjusts revenues that customers pay accordingly. Such revenue stabilizing mechanism is not in place in Pennsylvania.

In the Southern California Edison proceeding, three other California utilities were directed to participate: Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company. A second phase was set up in which Southern California Gas was excluded and Sierra Pacific added.

Southern California Edison was later used as a benchmark for establishing the AER/ECAC split for the other electric utilities. For the three utilities, the Commission first set the cap. The Commission sought earnings caps which would have similar financial impacts on the three utilities as the 160 basis point cap has on Southern California Edison. It acknowledged that a comparison of one utility to another does not automatically produce an appropriate answer, and that considerable judgment is involved in setting a cap.

Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Sierra Pacific were all judged to be more risky than

Southern California Edison. Therefore, their caps in terms of basis points were all lower.

Utility	Before-Income Tax Return on Common Equity Cap	Approximate After-Income Tax Return on Common Equity Cap
Southern California Edison	1.60%	0.80%
Pacific Gas & Electric Co.	1.40	0.70
San Diego Gas & Electric Co.	1.20	0.60
Sierra Pacific Resources	1.20	0.60

The approximate dollar exposure to investors due to the cap is as follows:

Southern California Edison	$32.0 million
Pacific Gas & Electric Company	$38.4 million
San Diego Gas & Electric Company	$6.7 million
Sierra Pacific Resources	$280 thousand

In setting the percentage distribution between the AER and ECAC, the California Commission relied upon the frequency with which a Company would encounter the limitations imposed by the cap. For instance, it was noted that for Southern California Edison, based on observations of earnings fluctuations, that Company's $32 million would be reached 19% of the time. It sought to achieve the same probability of reaching the cap for the other companies.

The California Commission, in applying an incentive fuel clause to other electric utilities, attempted to attain symmetry among the utilities commensurate with risk. It also attempted to proceed with caution in applying a previously untried, untested and highly problematical ratemaking technique. If this Commission decides to implement an incentive ECR, I recommend that it proceed with the same cautious reserve.

Q. WHAT ARE THE MAJOR DIFFERENCES IN THE NEW YORK APPLICATION OF THE INCENTIVE FUEL ADJUSTMENT CLAUSE FROM THE CALIFORNIA APPLICATION?

A. There are three. First, New York decided not to generically apply the concept to all utilities. It applied it to only one company, Niagara Mohawk Power Corporation. In a generic proceeding in 1980, the New York Public Service Commission decided that there was inadequate record support for a general application. The New York Public Service Commission decided instead to review the fuel adjustment charge on a case-by-case analysis of the operations of each electric utility under its jurisdiction. It chose Niagara Mohawk as the first candidate because of its diverse generating mix. It reasoned, "The diverse generating mix will allow us to examine how costs are affected by changes in the price of many fuel sources, as well as the operating costs and efficiencies of generating units that are fired by different fuels." (Page 9 of Opinion No. 80-24, dated June 18, 1980, Case No. 27137 Re: Investigation of Fuel Adjustment Clauses of Electric Utilities.)

The second difference from California is that the New York Commission included in the incentive fuel clause only variable fuel costs.

Thirdly, the New York Commission adopted a formula which allows Niagara Mohawk to recover 80% of the first $50 million in variation from total fuel cost and 90% of the next $50 million variation. If the variation is greater than $100 million annually, then a 100% pass-through similar to the 100% existing ECR pass-through would apply. The net result is that Niagara Mohawk stockholders are at risk for $15 million in unrecovered fuel costs. I characterize this as a prudent and cautious first step in implementing an incentive fuel clause.

In modifying the fuel clause, the Commission sought not to pose a threat to Niagara Mohawk's financial health. On the other hand, it noted that there were serious allegations of deficiencies in operating practices and felt that some modification was warranted.

Q. IN YOUR OPINION, IS THERE A COMMON ELEMENT IN REGULATORY COMMISSION TREATMENT OF INCENTIVE FUEL CLAUSES FOR THE COMPANIES YOU HAVE STUDIED?

A. Yes. Both Commissions expressed concern about adding to the risk of investing in the utilities to which an incentive fuel clause was being applied. In California, there was the studied effort in installing the incentive fuel clause to avoid adding to the intrinsic risk of investing in the utilities. An effort was made to restrict exposure to loss to the extent that investment risk is not increased. The California Commission relied on quantitative analyses aimed at measuring the impact of the clause on investors' perception of risk. While any such analysis is by its nature judgmental and subjective, the use thereof demonstrates a concern.

The same concern was expressed in New York. New York rejected the contention that an incentive fuel clause should be applied without a detailed study. It decided to apply it on a case-by-case basis. Only in the instance of Niagara Mohawk did it decide to apply it because the record before the Commission indicated that there was substantial room for improvement in Niagara Mohawk's fuel management practices. The New York Commission proceeded to implement the incentive fuel clause in a very cautious manner. Niagara Mohawk investors are exposed only to a $15 million before-income tax loss related to the incentive fuel clause.

Q. HOW DOES THE RISK TO INVESTORS IN PECO COMPARE WITH THE RISK TO INVESTORS IN OTHER COMPANIES THAT HAVE INCENTIVE FUEL ADJUSTMENT CLAUSES?

A. I have made that comparison in Schedules 3 and 4. These schedules display certain indicators of risk of PECO and the other companies I have studied with incentive fuel adjustment clauses. Schedule 3 contains data for PECO. Schedule 4 contains data for the five companies: Niagara Mohawk, Pacific Gas and Electric Company, San Diego Gas and Electric Company, Sierra Pacific Resources, and Southern California Edison Company. In addition, the average of the five companies is contained on page 1 of Schedule 4. It contains: earnings-price ratios, market-to-book ratios, dividend yields, capital structure ratios, earned rate of return on average booked common equity, various measures of coverage and various measures of quality of earnings. The measures of coverage are calculated both including and excluding AFC. Measures of quality of earnings are AFC as a percent of income available for common equity, effective income tax rate, internal cash generation as a percent of gross construction expenditures and common dividend coverage. A review of these indices leads to the inescapable conclusion that PECO is clearly the most risky of the companies having an incentive fuel adjustment clause.

The market based financial ratios all indicate PECO is riskier than the other companies. They demonstrate that the PECO market price of stock is depressed and has been more depressed relative to the stock of the others. The earnings-price ratio shows that only Niagara Mohawk has a higher five-year average, and Pacific Gas and

Electric has the same five-year average as PECO. PECO is higher than both in 1984, and higher than PG&E in 1983. PECO has a lower average market-to-book ratio over the five years. In 1984 and 1983, it is lower than any of the other companies. Its dividend yield is higher throughout the period. These indices indicate that investors in PECO securities require a premium return over the other securities.

In terms of financial risk measured by the common equity ratio, PECO has the lowest common equity ratio of all companies compared, and therefore, the highest degree of financial risk. Only Sierra Pacific Resources has earned less on book common equity, and its coverages are lower.

In comparison to the other companies studied, PECO has very poor quality earnings over the five-year period as shown on Schedules 1 and 2. PECO has averaged 83.5% AFC as a percent of income available for common equity. Therefore, even though its 12.8% average return on booked common equity is only slightly less than the average of other companies, only a small portion of those earnings are cash. It generated less cash in relationship to its construction expenditures. Its common dividend coverage is lowest. By these measures, it is apparent that PECO is less healthy in terms of its cash position than any company having an incentive fuel clause.

I reiterate that the indices shown on Schedules 3 and 4 indicate that PECO is certainly the most risky company having an incentive fuel adjustment clause. Others share this opinion. The basis of my belief is the information shown on Schedule 5. On Schedule 5, I have shown the current bond ratings of PECO and the

five companies. As shown on this Schedule, only PECO is at the bottom investment grade rating.

Q. WHAT CONCLUSION DO YOU DRAW FROM SCHEDULES 1, 2 AND 3?

A. If equal treatment is to be afforded, the exposure to which investors in PECO should be subjected because of an incentive fuel adjustment clause should be less than for any of the companies to which such a clause has been applied. This would apply consistent regulatory treatment among the companies.

Q. DO YOU HAVE A SPECIFIC RECOMMENDATION CONCERNING PECO AND AN ECR MODIFICATION?

A. Yes. Because of the experimental nature of the 80/20 proposal and because of PECO's very sub-standard financial starting point, there should be a limitation to the exposure to variation in fuel costs at the outset. I therefore recommend that this Commission follow the precedent established by the California and New York regulatory agencies and incorporate a cap into the incentive ECR formula. This is necessary in order to prevent further downgrading of PECO First Mortgage Bonds and minimize the possibility of an increase in the cost rate for PECO capital, both debt and equity, for the protection of consumers.

Q. WHAT SPECIFIC CAP DO YOU RECOMMEND?

A. I believe the maximum exposure of loss to PECO investors should be an approximated 1/2 of 1% after income tax return on total company common equity. The basis of my belief is 1) at this point PECO is more risky than the other companies whose regulatory agencies have modified full timely ECR recovery in terms of a cap intended to minimize after-income tax impact on return on common equity; 2) PECO

coverages are and will remain low for a few years; and 3) a regulatory signal to investors and rating agencies of caution and moderation is needed to avoid a possible higher cost of capital than otherwise.

Q. SINCE THE CAP IS RELATED TO THE ECR WHICH IN TURN IS RELATED TO RETAIL ELECTRIC RATES IN PENNSYLVANIA, WHAT SPECIFIC DOLLAR AMOUNT DO YOU RECOMMEND AS A CAP?

A. My recommendation proceeds, as I previously indicated, from the notion that an impact greater than 1/2 of 1% on the total company common equity is a reasonable yardstick for the reasons that I have cited. PECO's bond rating and investor perception of the risk from a stockholder's view is on a total company basis because each dollar of investment in PECO's various endeavors (retail electric, wholesale electric, gas, steam, etc.) is presumed to be financed in a manner proportionate to the total company. The prospective dollar amount of total company common equity would average approximately $350 million over the course of the next few years. One half of one percent of $350 million is $17.5 million on an after-income tax basis and, based on an assumed income tax rate of approximately 50%, a dollar cap of approximately $35 million is suggested.

Q. WHAT DOES A $35 MILLION CAP REPRESENT WHEN EXPRESSED AS A PERCENT OF THE COMPANY'S RETAIL ELECTRIC RATE BASE CLAIMED IN THIS PROCEEDING?

A. The Company's rate base claim in this proceeding is approximately $6.964 billion. Accordingly, a $35 million cap relative to a $6.964 billion rate base suggests a one half of one percent before-income tax impact on overall rate of return and an after-income tax impact on overall rate of return of approximately 1/4 of 1%, assuming, for

the purpose of illustration, a 50% income tax rate.

Q. IS THE $35 MILLION CAP YOU RECOMMEND AS APPROPRIATE FOR PECO MORE OR LESS THAN THE DOLLAR AMOUNT OF CAP EMPLOYED BY EITHER THE CALIFORNIA COMMISSION RELATIVE TO FOUR ELECTRIC COMPANIES OR THE NEW YORK COMPANY WHICH ALSO HAS A CAP IMPOSED BY THE NEW YORK PUBLIC SERVICE COMMISSION?

A. The $35 million cap I recommend for PECO is more than the dollar amount of cap established by either the New York Commission or the California Commission with the exception of Pacific Gas & Electric Company. I previously mentioned that the cap for Niagara Mohawk was $15 million; the cap for Sierra Pacific Resources was $280 thousand; for San Diego Gas & Electric the cap was $6.7 million, and Southern California Edison had a cap of $32.0 million. The cap for Pacific Gas & Electric Company was established at $38.4 million. Undoubtedly, there is a relationship between the size of the company and the magnitude of the cap, although size alone obviously cannot and should not be the sole criteria used to establish a cap. Schedule 5 displays various indices of size relating PECO to the other five companies. In terms of bond rating, PECO is closest to Niagara Mohawk, whose cap was set at $15 million.

I believe a $35 million cap for PECO is as high as prudently possible at this time. A cap more than $35 million would run the risk of an 80% ERC becoming counter productive to consumers as well as investors, particularly for a company whose investors believe the risk is above the industry average at the outset of the ECR modification and with new risks on the horizon such as FASB-71 and an income tax law change.

Admittedly, a $35 million cap is judgmental. However, while an ECR modification may be an appropriate incentive mechanism for the average risk electric, PECO, at the moment, is not an average risk electric and, thus, a cap is an appropriate judgment at this time until PECO can actually experience better achieved results and other uncertainties, such as FASB-71, have been resolved.

Q. IS IT YOUR TESTIMONY THAT THE LIKELY RANGE OF IMPACT ON RETURN ON COMMON EQUITY OCCASIONED BY AN 80/20 MODIFICATION TO THE ECR IS A RANGE OF JUST AN APPROXIMATE 1/2 OF 1% ON TOTAL PECO COMMON EQUITY, OR 1/4 OF 1% ON THE RETAIL ELECTRIC RATE BASE IN PENNSYLVANIA, BOTH ON AN AFTER-INCOME TAX BASIS OR $35 MILLION ON A BEFORE-INCOME TAX BASIS?

A. No. An 80/20 ECR, standing alone, obviously has a greater potential impact, and this is a primary reason for establishing a cap for the initial application of this experimental program. Setting an incentive fuel adjustment clause admittedly is a new procedure, and other Commissions have proceeded cautiously in applying them. I recommend that this Commission do the same. Once experience has been gained with this clause, adjustments can be made as warranted.

Q. WILL THE PRESENCE OF A REASONABLE CAP BE IMPORTANT TO THE INVESTMENT COMMUNITY?

A. Yes. I believe it is imperative to send a signal to the financial community that a change in the ECR which, without question, places the Company at greater risk, will not have undue adverse financial effect because at this time PECO is already considered to be one of the more risky electric companies in the country. That signal must take the form of a cap, or the modification of the ECR could prove

counter productive to PECO consumers and investors at this time. Moreover, the Commission itself apparently believes in caps, as evidenced by the fact that it has placed a cap of $3.2 billion on the construction costs relating to Limerick 2. If a cap is in the public interest with respect to the cost of construction of utility plant, fairness it seems would dictate a cap with respect to impact on investors with respect to expenses largely beyond the control of the Company. As a generalization, I believe it is fair to say, and I believe the data I have provided in my exhibits demonstrates, PECO is more investment risky than are the five electric companies included in my study which have implemented changes in their fuel adjustment procedures. Clearly, under such circumstances, a cap of $35 million on a before-income tax basis with respect to financial impact is the maximum cap appropriate.

Finally, for clarification it should be stated that a cap is a two-way street. To the extent there is a reduction in fuel and interchange costs up to but not more than $35 million, stockholders would be afforded an opportunity to experience a better rate of return on rate base and common equity than otherwise. To the extent there is a reduction of more than $35 million, the other side of the $35 million cap coin is a pass-through to consumers of any excess savings.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit JFB-2

PHILADELPHIA ELECTRIC COMPANY

Exhibit to Accompany
the Supplemental Direct Testimony

of

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

Concerning

Energy Cost Rate

PHILADELPHIA ELECTRIC COMPANY
ESTIMATED IMPACT ON NET INCOME
ASSUMING ONLY 80% OF FUEL COSTS
ARE SUBJECT TO RECOVERY THROUGH
THE ENERGY COST RATE (ECR)

SCENARIO(S)	INCREASE IN FUEL AND INTER-CHANGE COSTS (1) (A)	IMPACT ON BEFORE INCOME TAX INCOME (2) (B)	INCOME TAX AT ASSUMED 50% RATE (C)	IMPACT ON NET INCOME (DECREASE) (COL B - C) (D)	COMMON EQUITY AT 12-31 (3) (E)	DECREASE IN RATE OF RETURN ON AVERAGE COMMON EQUITY (COL D÷COL E) (F)
JUNE 30,1987						
COAL SCENARIO	$108904230	$21780846	$10890423	$10890423	$3420000000	0.32%
NUCLEAR SCENARIO	129438261	25887652	12943826	12943826	3420000000	0.38
JUNE 30,1988						
COAL SCENARIO	$137436473	$27487295	$13743647	$13743647	$3585000000	0.38
NUCLEAR SCENARIO	141349722	28269944	14134972	14134972	3585000000	0.39
JUNE 30,1989						
COAL SCENARIO	$136827857	$27365571	$13682786	$13682786	$3753000000	0.36
NUCLEAR SCENARIO	232231163	46446233	23223116	23223116	3753000000	0.62

NOTES:
(1) COMPANY PROVIDED
(2) 20% OF COLUMN A
(3) DECEMBER 31 IS THE MIDPOINT OF THE TWELVE MONTHS ENDED JUNE 30. THE ESTIMATE OF COMMON EQUITY AT YEARS-END 1986-1988 ARE DEVELOPED ON SCHEDULE 1, PAGE 2.

SCENARIOS DEFINED:
COAL SCENARIO - LOW RIVER HYDRO OUTPUT, FUEL PRICE INCREASE IN 1st YEAR, TWO PARTY PURCHASES LIMITED TO 1,000 MW, AND PJM COAL CAPACITY FACTOR LIMITED TO 62.2%.
NUCLEAR SCENARIO - FUEL PRICE INCREASE IN 1st YEAR, TWO PARTY PURCHASES LIMITED TO 1,000 MW, AND NUCLEAR GENERATION ON PJM REDUCED TO 49.9%.

Exhibit JFB-2
Schedule 1
Page 1 of 2

PHILADELPHIA ELECTRIC COMPANY
DEVELOPMENT OF
ESTIMATED COMMON EQUITY
AT 12-31-85 TO 12-31-88, INCLUSIVE

	(MILLIONS)
TOTAL COMMON EQUITY AT 12-31-84(1)	$2891
+ COMMON STOCK ISSUANCES(2)	211
+EARNINGS RETAINED(3)	100
TOTAL COMMON EQUITY AT 12-31-85	3202
+ COMMON STOCK ISSUANCES(2)	168
+EARNINGS RETAINED(3)	50
TOTAL COMMON EQUITY AT 12-31-86	3420
+ COMMON STOCK ISSUANCES(2)	115
+EARNINGS RETAINED(3)	50
TOTAL COMMON EQUITY AT 12-31-87	3585
+ COMMON STOCK ISSUANCES(2)	118
+EARNINGS RETAINED(3)	50
TOTAL COMMON EQUITY AT 12-31-88	$3753

NOTES: (1) COMPANY'S FILING, ATTACHMENT III-A-2
(2) COMPANY'S FILING, ATTACHMENT III-F-2
(3) SUPPORTING DATA FOR III-F-2, PROVIDED BY COMPANY

Philadelphia Electric Company
Calculation of Before Income Tax Interest Coverage
Including and Excluding All AFC and Assuming
AFC Related to Limerick 1 Becomes Cash Earnings

Type of Capital	Approximate Ratios (1)	Rate	After Income Tax Weighted Rate	Before Income Tax Weighted Rate (2)
Including All AFC				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	15.43 (4)	5.86	11.72
	100%		12.44%	19.46%
Before income tax interest coverage (19.46% ÷ 5.42%)				3.6x
Excluding All AFC				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	1.19 (5)	0.45	0.90
	100%		7.03%	8.64%
Before income tax interest coverage (8.64% ÷ 5.42%)				1.6x
Assuming AFC Related to Limerick 1 Becomes Cash Earnings				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	12.04 (6)	4.58	9.16
	100%		11.16%	16.90%
Before income tax interest coverage (16.90% ÷ 5.42%)				3.1x

See page 3 for notes.

Philadelphia Electric Company
Calculation of Before Income Tax Interest Coverage
Including and Excluding All AFC and Assuming AFC related to Limerick 1 Becomes Cash Earnings
and After Reflecting Largest Decline in Return on Common Equity Due to 80/20 ECR

Type of Capital	Approximate Ratios (1)	Rate	After Income Tax Weighted Rate	Before Income Tax Weighted Rate (2)
Including All AFC				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	14.81 (7)	5.63	11.26
	100%		12.21%	19.00%
Before income tax interest coverage (19.00% ÷ 5.42%)				3.5x
Excluding All AFC				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	0.57 (8)	0.22	0.44
	100%		6.80%	8.18%
Before income tax interest coverage (8.18% ÷ 5.42%)				1.5x
Assuming AFC Related to Limerick 1 Becomes Cash Earnings				
Long-term debt	51%	10.63% (3)	5.42%	5.42%
Preferred stock	11	10.54 (3)	1.16	2.32
Common equity	38	11.42 (9)	4.34	8.68
	100%		10.92%	16.42%
Before income tax interest coverage (16.42% ÷ 5.42%)				3.0x

See page 3 for notes.

Philadelphia Electric Company
Calculation of Before Income Tax Interest Coverage
Including and Excluding All AFC and Assuming
AFC Related to Limerick 1 Becomes Cash Earnings

Notes:

(1) Approximate capital structure ratios at time rates for service in this proceeding will go into effect.

(2) Based on an assumed 50% income tax rate.

(3) Approximate long-term debt and preferred stock cost rate at June 30, 1986 updated to reflect known changes to Company's financing plan.

(4) Return rate on common equity based on income available for common equity per Company's budgeted June 30, 1986 Income Statement (shown on Schedule B-8 of Exhibit TPH-2) and the estimated balance of common equity of $3,202 million at December 31, 1985 developed on page 2 of Schedule 1 ($494,013 million ÷ $3,202 million = 15.43%).

(5) Return rate on common equity based on income available for common equity per Company's budgeted June 30, 1986 Income Statement (shown on Schedule B-8 of Exhibit TPH-2) of $494.013 million minus total AFC of $455.850 million including $92.298 million included as other income as provided by the Company and the estimated balance of common equity of $3,202 million at December 31, 1985 developed on page 2 of Schedule 1 ($494.013 million $455.850 million = $38.163 million ÷ $3,202 million = 1.19%).

(6) Return rate on common equity based on income available for common equity per Company's budgeted June 30, 1986 Income Statement (shown on Schedule B-8 of Exhibit TPH-2) of $494.013 million minus total AFC of $455.850 million plus $347.452 million of AFC related to Limerick 1 as provided by the Company and the estimated balance of common equity of $3,202 million at December 31, 1985 developed on page 2 of Schedule 1 ($494.013 million - $455.850 million + $347.452 million = $385.615 million ÷ $3,202 million = 12.04%).

(7) Developed by reducing the return rate on common equity calculation in Note (4) of 15.43% by the largest reduction in return rate on common equity of 0.62% as calculated on Schedule 1, page 1 (15.43% - 0.62% = 14.81%).

(8) Developed by reducing the return rate on common equity calculation in Note (5) of 1.19% by the largest reduction in return rate on common equity of 0.62% as calculated on Schedule 1, page 1 (1.19% - 0.62% = 0.57%).

(9) Developed by reducing the return rate on common equity calculation in Note (6) of 12.04% by the largest reduction in return rate on common equity of 0.62% as calculated on Schedule 1, page 1 (12.04% - 0.62% = 11.42%).

STANDARD & POOR'S CREDITWEEK

CreditComment

Electric utility benchmarks revised

S&P recently developed new, more conservative financial benchmarks for rating investor-owned electric utility bonds. In light of the increasing business and industry risks confronting electric utilities, more conservative financial profiles are necessary to maintain creditor protection.

The new benchmarks are not expected to result in substantial revisions of outstanding ratings since they do not signal a fundamental change in rating standards or methodologies. Rather, they serve to highlight the evolving risks in the electric utility business. As a practical matter, rating analyses have been incorporating more stringent financial standards for some time.

S&P's rating perspective involves a prospective look at a utility's financial performance. Estimates of future earnings, cash flow, and debt levels are matched against the benchmarks to help determine the financial protection that will be available for bondholders. Also, analyses will continue to encompass substantially more than comparisons of financial ratios with rating benchmarks. Where qualitative business or industry risk elements exist, such as unresponsive regulation, weak or highly cyclical service territory economies, uncertain construction, or high potential acid rain exposure, S&P will continue to look for a more conservative financial profile than indicated by the benchmarks for a particular rating category.

Business risk for electric utilities continues to increase. Sales growth is no longer assured. Annual usage increases of 8%–10%, once common in the past, are unlikely in the future. For some utilities, the likelihood of any usage increase is remote. Major customers are seeking alternatives to traditional utility service, some through cogeneration, some by trying to make their own deals with other utilities.

Service costs are increasing because of fuel costs, regulation, and inflated capital and construction costs. As those costs go up, utilities are finding themselves in double jeopardy. First, political regulators may be unwilling or unable to authorize rates sufficient to cover rising costs. Second, rates high enough to fully cover costs might price electric service beyond the ability or willingness of customers to pay. Utility plant investment has become a risky proposition. Regulators are becoming increasingly reluctant to recognize operating plant in service.

Utility investment is also becoming less economical and more unproductive. For example, acid rain remedies could cost billions of dollars to implement, and they will not generate more electricity, nor will they increase the efficiency of utility assets. Both regulators and common stock investors are likely to react unfavorably. In addition, the government's tax reform proposals seem designed with the specific intent of crippling smokestack industries, including electric utilities. All this translates into heightened risk for utility bondholders. The new financial benchmarks will more accurately relate the debt ratings to the risks.

New benchmarks
Electric utilities

	'AAA'	'AA'	'A'	'BBB'	'BB'
Pretax interest coverage (excl. AFDC*) (x)	Greater than 4.5	3.5–5.0	2.5–4.0	1.5–3.0	Less than 2.0
Net cash flow/ permanent capital (%)	Greater than 10.0	7.0–11.0	5.0–8.0	2.5–6.0	Less than 3.0
Debt leverage (%)	Less than 41	39–46	44–52	50–58	Greater than 56

*Also excludes other noncash accruals.

Obsolete benchmarks—superseded Jan. 28, 1985
Electric utilities

	'AAA'	'AA'	'A'	'BBB'
Pretax interest coverage (incl. AFDC) (x)	Greater than 4.0	3.25–4.25	2.50–3.50	Less than 3.0
Net cash flow/ cash construction (%)	(None published)	Greater than 40	20–50	Less than 30
Debt leverage (%)	Less than 45	42–47	45–55	Greater than 53

Debt leverage

Debt leverage benchmarks were shaved by several hundred basis points across the board. The most readily available response to increasing industry and business risk is a less leveraged capital structure. A solid 'AA' capital structure would have debt leverage sustainable at about 40% of capital, less than 10% preferred stock, and common equity of 50% or more.

The net cash flow-to-total capital ratio will be used to determine the adequacy of cash flow. The former benchmarks related cash flow to construction expenditures. But construction is not a very stable series, especially when base load generation

S&P electric utility financial benchmark ratio definitions

Pretax interest coverage: The sum of net income, gross interest charges, and income taxes divided by gross interest charges. For coverages excluding AFDC, deduct total AFDC (debt and equity components) from the numerator.

Debt leverage: The sum of long-term debt, current maturities and short-term borrowings used for bridge financing, divided by permanent capital. Numerator and denominator include off balance sheet obligations.

Permanent capital: The sum of long-term debt, current maturities, short-term borrowings used for bridge financing, off balance sheet obligations, and all stockholders' equity.

Gross cash flow: The sum of net income, depreciation, depletion, amortization, net deferred income taxes, and net investment tax credits, less total AFDC.

Net cash flow: Gross cash flow, less preferred, preference, and common dividends.

Cash construction: Gross construction capitalized, less total AFDC.

is involved. The ratio tends to be volatile, and it does not adequately depict either stability or sufficiency of utility cash flow. Cash flow-to-capital is a preferable alternative. Net cash flow-to-capital of 10%—a 10-year turnover of the investment base—is achievable with good earnings performance, realistic depreciation, and conservative tax and accounting policies. This level of cash generation is appropriate for a solid 'AA' senior debt rating. However, S&P will continue to analyze construction expenditures. When they are heavy, S&P will look for sufficient cash flow to fund the program without creating undue external financing stress.

The biggest difference from previously published benchmarks flows from the income statement. The allowance for funds used during construction (AFDC) can no longer be considered as a source of genuine earnings protection. As the proportion of AFDC climbed in recent years, analytical confidence in the quality of the assets created by AFDC accruals has gone down sharply.

AFDC represents more than half of industry earnings. The result is a real return on investment that is completely uncompetitive with capital market-driven rates, and common dividends that are paid out of illusory profits.

The new electric utility benchmarks are more stringent to reflect the evolving risks in the electric utility business. The industry's risk in 1985 is not compatible with the average 'AA' debt rating it enjoyed in 1970. The new benchmarks demonstrate that utilities need stronger financial profiles to achieve and sustain strong ratings than in the past.

Douglas Randall

Railroad acquisition activity rolls ahead

Recent events suggest further consolidation of the railroad industry. Norfolk Southern Corp. was selected by the Department of Transportation (DOT) to acquire Consolidated Rail Corp. (Conrail). A federal bankruptcy court in Chicago ruled in favor of Soo Line Railroad Co.'s bid to acquire the core assets of the Milwaukee Road, formally known as the Chicago, Milwaukee, St. Paul & Pacific Railroad Co. Katy Industries announced that it was negotiating with a buyer for its Missouri-Kansas-Texas Railroad subsidiary.

S&P views the probable credit effect of these events as neutral for Norfolk Southern's railroad subsidiaries, negative for the Soo Line, and positive for the Missouri-Kansas-Texas Railroad. Because the outcome of these transactions is uncertain and may not be finalized for a year or more, S&P will not take any rating action at this time.

Norfolk Southern Corp.

Norfolk Southern Corp., the holding company formed by the 1982 merger of the Norfolk & Western and the Southern railways, agreed to pay $1.2 billion for the government's 85% interest in Conrail and offered Conrail's employees $375 million for their 15% interest. The company also agreed last year, subject to Interstate Commerce Commission approval, to acquire North American Van Lines, the nation's fifth largest commercial trucking company, for $315 million. Norfolk Southern has no rated debt; however, S&P rates the subsidiary railroad's equipment trust certificates 'AAA' and mortgage bonds 'AA'.

Norfolk Southern's total debt to capital ratio of 17.6% on Dec. 31, 1984 included $961.2 million of debt and $4.5 billion of equity. Cash flow of $904.9 million covered 94% of its total debt while cash and short-term investments amounted to $1.0 billion. The exceptional financial strength of Norfolk Southern, which has no debt beyond that of the railroad operating companies, suggests a strong capacity to finance both acquisitions without any significant impairment of creditworthiness.

To complete the Conrail sale, Congressional approval is needed. S&P anticipates that this will entail lengthy hearings addressing shipper, labor, and other carrier concerns. Under the provisions of the 1981 Northeast Rail Services Act, which mandated the return of Conrail to the private sector, Interstate Commerce Commission approval of the sale is not needed. Norfolk Southern agreed to a number of conditions to keep Conrail healthy and preserve competition in the combined service territory. A Norfolk Southern-Conrail combination would create a 31,500-mile system serving 24 states east of the Mississippi.

Soo Line Railroad Co.

Soo Line Railroad Co.'s $571 million bid to acquire the core assets of the Milwaukee Road was selected over a competing $786 million offer made by the Chicago & Northwestern Transportation Co. (C&NW). In his decision in favor of the Soo, the judge stated that the Soo Line-Milwaukee combination would better preserve competition and jobs than would the C&NW-Milwaukee combination. S&P expects that Chicago Milwaukee Corp., parent of the Milwaukee Road, may challenge the court's selection of the lower Soo Line bid.

Financing of the acquisition could weaken the ratings of approximately $100 million of equipment and mortgage debt of Soo Line and its predecessor Wisconsin Central Railroad and Minneapolis St. Paul & Sault Ste. Marie Railway. The $571 million purchase price, consisting of cash and the assumption of Milwaukee Road obligations, would significantly alter Soo Line's capital structure, which included $107.5 million of debt and $274.9 million of equity at Sept. 30, 1984.

Soo Line, an upper-midwestern carrier that is 55.7% owned by Canadian Pacific Ltd., would nearly double its current size and gain access to the Kansas City and Louisville gateways with the addition of Milwaukee's 3,100-mile system. For the first nine months of 1984, the Milwaukee Road earned $14.6 million on revenues of $331.1 million while the Soo earned $14.0 million on revenues of $237 million.

Missouri-Kansas-Texas Railroad

Katy Industries announced that it is seeking a buyer for its 98%-owned Missouri-Kansas-Texas Railroad (M-K-T) subsidiary. While the buyer is unnamed, company announcements suggest that it is another railroad. The M-K-T is operating profitably now after experiencing losses for much of the last 30 years. The system extends from Kansas City to the Gulf of Mexico via Dallas, Fort Worth, and Houston and has about $250 million in annual revenue. Its mortgage bonds are rated 'B' and nonpaying income debentures 'C'. Consolidation with a larger system could enhance M-K-T's creditworthiness.

Marna P. Dann

PHILADELPHIA ELECTRIC COMPANY
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
INANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	21.6%	15.1%	15.7%	17.6%	14.1%	16.8%
MARKET/AVERAGE BOOK RATIO	69.9	88.4	84.7	69.3	75.1	77.5
DIVIDEND YIELD	17.6	13.4	13.5	14.9	12.7	14.4
APITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	52.4%	50.0%	51.1%	51.7%	51.2%	51.3%
PREFERRED STOCK	11.3	12.0	11.2	11.9	13.3	11.9
COMMON EQUITY	36.3	38.0	37.7	36.4	35.5	36.8
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	54.0%	51.9%	51.6%	52.1%	51.8%	52.3%
PREFERRED STOCK	10.9	11.5	11.0	11.8	13.1	11.7
COMMON EQUITY	35.1	36.6	37.4	36.1	35.1	36.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
TE OF RETURN ON AVERAGE BOOK COMMON EQUITY	15.0%	13.3%	13.2%	12.1%	10.6%	12.8%
VERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.4x	2.4x	2.4x	2.1x	2.1x	2.3x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.1	2.1	2.0	1.9	2.0	2.0
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.8	1.7	1.7	1.6	1.6	1.7
VERAGES-EXCLUDING ALL AFC (3)						
EFORE INCOME TAXES: ALL INTEREST CHARGES	1.6x	1.6x	1.7x	1.5x	1.5x	1.6x
FTER INCOME TAXES: ALL INTEREST CHARGES	1.3	1.3	1.4	1.3	1.3	1.3
VERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.1	1.1	1.2	1.1	1.1	1.1
LITY OF EARNINGS						
FC/INCOME AVAILABLE FOR COMMON EQUITY	86.6	85.8	76.5	84.4	84.3	83.5
FFECTIVE INCOME TAX RATE	20.9	22.4	28.2	19.3	16.4	21.4
NTERNAL CASH GENERATION/GROSS CONSTR. (4)	5.2	8.9	11.5	2.8	3.6	6.4
OMMON DIVIDEND COVERAGE (5)	1.1x	1.2x	1.3x	1.1x	1.1x	1.2x

PAGE 2 FOR NOTES.

Philadelphia Electric Company
Selected Risk Indices and Financial Ratios
1980-1984, Inclusive

Notes:

(1) Based upon financial statements as originally reported in each year.

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

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

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures, excluding all AFC, provided by internally generated funds from operations, excluding all AFC, and after payment of all cash dividends.

(5) Common dividend coverage is the relationship of internally generated funds from operations, excluding all AFC, and after payment of preferred stock dividends to common dividends paid.

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

GROUP OF FIVE ELECTRIC COMPANIES HAVING INCENTIVE FUEL CLAUSES
SELECTED RISK INDICES AND FINANCIAL RATIOS (6)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	16.3%	15.0%	17.7%	16.9%	13.4%	15.9%
MARKET/AVERAGE BOOK RATIO	96.3	100.4	85.7	76.2	74.5	86.6
DIVIDEND YIELD	10.9	10.2	11.6	12.5	11.9	11.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	48.1%	47.5%	46.2%	47.2%	47.5%	47.3%
PREFERRED STOCK	10.7	11.8	13.0	13.8	14.2	12.7
COMMON EQUITY	41.2	40.7	40.8	39.0	38.3	40.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	48.9%	48.8%	48.3%	50.6%	50.6%	49.4%
PREFERRED STOCK	10.5	11.5	12.5	12.9	13.3	12.2
COMMON EQUITY	40.6	39.7	39.2	36.5	36.1	38.4
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	15.3%	15.0%	15.1%	13.0%	10.0%	13.7%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.3x	3.1x	2.9x	2.4x	2.1x	2.8x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.4	2.3	2.2	2.0	2.3
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.0	2.0	1.9	1.8	1.6	1.9
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.9x	2.5x	2.3x	1.9x	1.7x	2.3x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.0	1.8	1.8	1.7	1.5	1.8
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.6	1.5	1.5	1.4	1.3	1.5
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	38.3	49.4	44.5	53.0	64.4	49.9
EFFECTIVE INCOME TAX RATE	38.9	33.9	28.1	16.8	8.0	25.1
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	67.2	43.9	33.1	21.7	19.7	37.1
COMMON DIVIDEND COVERAGE (5)	2.5x	2.2x	2.0x	1.8x	1.8x	2.1x

SEE PAGE 7 FOR NOTES.

NIAGARA MOHAWK POWER CORPORATION
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	19.1%	16.4%	18.4%	19.2%	15.4%	17.7%
MARKET/AVERAGE BOOK RATIO	79.5	92.6	81.6	70.8	70.2	78.9
DIVIDEND YIELD	13.3	11.2	12.2	13.1	12.4	12.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	46.4%	45.2%	46.8%	45.8%	48.0%	46.4%
PREFERRED STOCK	11.9	12.9	11.9	13.3	12.8	12.6
COMMON EQUITY	41.7	41.9	41.3	40.9	39.2	41.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	47.0%	46.2%	48.0%	47.6%	49.8%	47.7%
PREFERRED STOCK	11.8	12.6	11.6	12.8	12.4	12.3
COMMON EQUITY	41.2	41.2	40.4	39.6	37.8	40.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	14.9%	15.0%	14.7%	13.5%	10.8%	13.8%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.1x	3.0x	3.0x	2.7x	2.5x	2.9x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.5	2.5	2.5	2.5	2.3	2.5
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.1	2.1	2.1	2.0	1.8	2.0
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.5x	2.4x	2.4x	2.2x	2.0x	2.3x
AFTER INCOME TAXES: ALL INTEREST CHARGES	1.8	2.0	2.0	2.0	1.8	1.9
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.5	1.6	1.6	1.6	1.5	1.6
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	52.4	43.6	41.0	38.6	44.2	44.0
EFFECTIVE INCOME TAX RATE	29.2	21.5	23.6	13.2	14.6	20.4
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	28.5	28.8	22.8	34.5	37.2	30.4
COMMON DIVIDEND COVERAGE (5)	1.8x	1.9x	1.7x	2.0x	2.1x	1.9x

SEE PAGE 7 FOR NOTES.

PACIFIC GAS & ELECTRIC COMPANY
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	17.9%	14.0%	20.0%	15.6%	16.4%	16.8%
MARKET/AVERAGE BOOK RATIO	89.1	97.4	81.1	74.2	75.3	83.4
DIVIDEND YIELD	11.4	10.1	11.7	12.3	11.6	11.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	49.0%	45.3%	45.0%	45.7%	44.5%	45.9%
PREFERRED STOCK	12.9	14.9	15.5	16.1	16.0	15.1
COMMON EQUITY	38.1	39.8	39.5	38.2	39.5	39.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	51.1%	47.3%	46.0%	50.4%	48.6%	48.7%
PREFERRED STOCK	12.3	14.4	15.2	14.7	14.8	14.3
COMMON EQUITY	36.6	38.3	38.8	34.9	36.6	37.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	16.0%	13.6%	16.0%	11.6%	12.0%	13.8%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.2x	3.2x	3.3x	2.3x	2.4x	2.9x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.3	2.4	2.1	2.2	2.3
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.0	1.8	1.9	1.7	1.8	1.8
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.5x	2.4x	2.6x	1.7x	1.8x	2.2x
AFTER INCOME TAXES: ALL INTEREST CHARGES	1.7	1.6	1.8	1.6	1.6	1.7
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.4	1.3	1.4	1.2	1.3	1.3
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	59.2	68.4	54.4	66.1	61.0	61.8
EFFECTIVE INCOME TAX RATE	35.8	38.0	37.3	9.6	12.1	26.6
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	53.0	34.2	12.4	12.4	16.1	25.6
COMMON DIVIDEND COVERAGE (5)	2.6x	2.1x	1.3x	1.4x	1.5x	1.8x

SEE PAGE 7 FOR NOTES.

SAN DIEGO GAS & ELECTRIC COMPANY
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	14.5%	16.4%	19.6%	18.7%	8.3%	15.5%
MARKET/AVERAGE BOOK RATIO	109.8	111.1	90.4	78.3	73.3	92.6
DIVIDEND YIELD	9.8	9.7	11.8	13.0	12.7	11.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	46.4%	47.7%	42.4%	46.0%	47.9%	46.1%
PREFERRED STOCK	9.8	10.4	14.8	15.0	14.3	12.8
COMMON EQUITY	43.8	41.9	42.8	39.0	37.8	41.1
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	46.4%	49.6%	47.4%	51.3%	53.9%	49.7%
PREFERRED STOCK	9.8	10.0	13.5	13.5	12.6	11.9
COMMON EQUITY	43.8	40.4	39.1	35.2	33.5	38.4
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	16.0%	18.2%	17.8%	14.7%	6.2%	14.6%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.9x	3.7x	3.0x	2.1x	1.5x	2.8x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.6	2.7	2.5	2.0	1.6	2.3
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.2	2.2	2.0	1.7	1.3	1.9
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.7x	2.9x	2.4x	1.6x	1.0x	2.3x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.0	1.8	1.5	1.1	1.8
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.0	1.6	1.4	1.3	1.0	1.5
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	14.7	48.8	54.1	54.4	114.3	57.3
EFFECTIVE INCOME TAX RATE	42.9	34.6	27.9	6.7	(19.5)	18.5
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	117.6	50.0	34.7	19.0	10.4	46.3
COMMON DIVIDEND COVERAGE (5)	3.2x	2.5x	2.1x	1.6x	1.3x	2.1x

SEE PAGE 7 FOR NOTES.

SIERRA PACIFIC RESOURCES
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	14.5%	11.9%	15.0%	12.7%	12.1%	13.2%
MARKET/AVERAGE BOOK RATIO	95.9	94.7	81.0	77.9	83.2	86.5
DIVIDEND YIELD	10.8	10.5	12.1	12.5	11.1	11.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	53.1%	52.5%	48.4%	50.2%	49.5%	50.7%
PREFERRED STOCK	9.1	10.4	11.7	13.0	14.3	11.7
COMMON EQUITY	37.8	37.1	39.9	36.8	36.2	37.6
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	53.4%	53.2%	51.2%	53.9%	51.4%	52.6%
PREFERRED STOCK	9.1	10.2	11.1	12.0	13.8	11.3
COMMON EQUITY	37.5	36.6	37.7	34.1	34.8	36.1
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	13.5%	11.3%	11.8%	10.1%	10.2%	11.4%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.8x	2.6x	2.5x	2.3x	2.3x	2.5x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.1	2.0	1.9	1.8	1.9	1.9
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.8	1.7	1.6	1.5	1.5	1.6
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.5x	2.4x	2.4x	1.9x	2.0x	2.2x
AFTER INCOME TAXES: ALL INTEREST CHARGES	1.7	1.8	1.8	1.5	1.6	1.7
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.5	1.5	1.5	1.2	1.3	1.4
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	35.5	26.8	10.0	50.4	39.0	32.3
EFFECTIVE INCOME TAX RATE	41.0	39.7	39.3	33.0	30.4	36.7
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	53.2	58.3	71.5	24.4	18.7	45.2
COMMON DIVIDEND COVERAGE (5)	2.2x	2.7x	3.3x	2.2x	2.3x	2.5x

SEE PAGE 7 FOR NOTES.

SOUTH CALIFORNIA EDISON COMPANY
SELECTED RISK INDICES AND FINANCIAL RATIOS (1)
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
FINANCIAL RATIOS-MARKET BASED						
EARNINGS/PRICE RATIO	15.3%	16.1%	15.8%	18.4%	14.7%	16.1%
MARKET/AVERAGE BOOK RATIO	107.0	106.1	94.5	79.6	70.5	91.5
DIVIDEND YIELD	9.5	9.3	10.2	11.3	11.6	10.4
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	45.8%	46.8%	48.3%	48.1%	47.5%	47.3%
PREFERRED STOCK	9.6	10.3	11.0	11.8	13.6	11.3
COMMON EQUITY	44.6	42.9	40.7	40.1	38.9	41.4
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	46.6%	47.9%	49.2%	50.1%	49.0%	48.5%
PREFERRED STOCK	9.4	10.1	10.8	11.4	13.2	11.0
COMMON EQUITY	44.0	42.0	40.0	38.5	37.8	40.5
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
RATE OF RETURN ON AVERAGE BOOK COMMON EQUITY	16.4%	17.1%	15.2%	15.3%	10.7%	14.9%
COVERAGES-INCLUDING ALL AFC (2)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.5x	3.0x	2.5x	2.8x	2.2x	2.8x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.4	2.3	2.3	2.4	2.1	2.3
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	2.1	2.0	2.0	2.0	1.7	2.0
COVERAGES-EXCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	3.2x	2.3x	1.8x	2.2x	1.6x	2.2x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.0	1.6	1.6	1.8	1.5	1.7
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.8	1.4	1.4	1.5	1.3	1.5
QUALITY OF EARNINGS						
AFC/INCOME AVAILABLE FOR COMMON EQUITY	29.6	59.4	62.9	55.3	63.6	54.2
EFFECTIVE INCOME TAX RATE	45.4	35.5	12.1	21.7	2.6	23.5
INTERNAL CASH GENERATION/GROSS CONSTR. (4)	83.8	48.4	23.9	18.1	15.8	38.0
COMMON DIVIDEND COVERAGE (5)	2.7x	2.1x	1.8x	1.7x	1.6x	2.0x

SEE PAGE 7 FOR NOTES.

Group of Five Electric Companies Having Incentive Fuel Clauses
Selected Risk Indices and Financial Ratios
1980-1984, Inclusive

Notes:

(1) Based upon financial statements as originally reported by each company in each year.

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

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

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures, excluding all AFC, provided by internally generated funds from operations, excluding all AFC, and after payment of all cash dividends.

(5) Common dividend coverage is the relationship of internally generated funds from operations, excluding all AFC, and after payment of preferred stock dividends to common dividends paid.

(6) Arithmetic average of each company in the group.

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

Current Bond Ratings of Philadelphia Electric Company and Five Companies Having Incentive Fuel Clauses

	November 1985 First Mortgage Bonds Debt Ratings	
	Moody's	S&P
Philadelphia Electric Company	Baa3	BBB-
Niagara Mohawk Power Corp.	A3	A-
Pacific Gas & Electric Co.	A1	A+
San Diego Gas & Electric Co.	Aa3	A+
Sierra Pacific Resources	Baa1	BBB+
Southern California Edison Co.	Aa2	AA

Source of Information: Moody's Public Utility Manual
S&P Bond Guide

Philadelphia Electric Company and Five Companies
Having Incentive Fuel Clauses
1984 Size Comparison

	PECO	Niagara Mohawk Power Corp.	Southern California Edison Co.	Pacific Gas & Electric Company	San Diego Gas & Electric Company	Sierra Pacific Resources
			($ Million of Dollars)			
Revenues	$2,981	$2,786	$4,901	$7,830	$1,621	$358
Electric Revenue	2,436	2,134	4,899	5,159	1,291	285
Net Plant	8,460	5,402	10,071	13,345	2,393	786
Average Total Capital	7,628	5,015	9,341	13,567	2,366	712

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

PECO Statement 18B

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

Further Supplemental
Direct Testimony

of

Thomas P. Hill, Jr.

DOCKETED
JAN 2 - 1986

DOCUMENT

SUMMARY OF PECO RESPONSE

TO ECR No. 8 ORDER RESPECTING

MODIFICATION OF THE ENERGY COST RATE

December 1985

PECO Statement No. 18B

FURTHER SUPPLEMENTAL DIRECT TESTIMONY
OF THOMAS P. HILL, JR.

Q. Mr. Hill, have you previously presented testimony in this proceeding?

A. Yes, I have presented Direct Testimony (Statement 18) and Supplemental Testimony (Statement 18A) in this proceeding. A full statement of my qualifications, education, employment history and prior testimony experience is set forth in my direct testimony.

Q. What is the purpose of your further supplemental direct testimony?

A. The purpose of my testimony is to present the Company's response to the Commission's Order in the ECR No. 8 Investigation, Docket No. M-840375 et al., entered October 30, 1985 (the "October 30 Order"). The October 30 Order requests the Company to file a modified Energy Cost Rate ("ECR") in which only 80% of total energy costs are subject to after-the-fact reconciliation for over/under collections (the "80%/20% ECR"), and to submit various data as set forth in Appendix B to the Commission's Order.

The Company's response is organized into four statements. Mr. Carroll's supplemental direct testimony (PECO Statement 22A) provides the data and information requested in Appendix B of the October 30 Order, develops

and supports the energy cost levels employed in the Company's revised ECR filing, and presents a computer analysis demonstrating the variability of these energy costs. Mr. Gallagher's direct testimony (PECO Statement 30) describes the Company's past and future actions to improve the performance of its generating units. Mr. Brennan's supplemental direct testimony (Statement 28A) analyzes the potential financial impact of the proposed 80%/20% ECR, describes the importance of a fair and balanced ECR to PECO, its customers, and the investment community, and develops the Company's proposed "cap" on the gain or loss resulting from application of an 80%/20% ECR. Finally, my testimony, drawing upon the analyses and recommendations of the other witnesses, presents the Company's overall response to the Commission's Order, including a description of the Company's proposed 80%/20% ECR.

Q. Mr. Hill, please summarize the Company's response to the Commission's Order.

A. Based on the magnitude, variability and uncontrollability of the Company's energy costs, the potential adverse financial impact of non-recovery of a portion of these costs on the Company's already substandard financial condition, and a proper balancing of ratepayer and shareholder interests, the Company believes that the current ECR mechanism should be maintained. Alternatively, if the proposed 80%/20% ECR is

adopted, the Company urges the Commission to adopt a reasonable limitation or "cap" on the amount of potential gain or loss to the Company and its customers. Such a cap would be beneficial to both the Company and its customers, would recognize the experimental nature of ECR incentive programs, would appreciably reduce the risk associated with the 80%/20% ECR as perceived by the financial community, and would be consistent with ECR incentive programs adopted in other jurisdictions.

Q. Mr. Hill, please describe the development of the Company's existing ECR and its predecessors.

A. From July 27, 1970 until January 1, 1974, the Company had in place a fuel adjustment mechanism which recovered increases in cost for low sulphur fuel oil burned in Company generating stations located within the City of Philadelphia. This adjustment clause, referred to as the Air Quality Fuel Charge, was adjusted quarterly to reflect changes in fuel oil prices over a pre-established base.

On January 1, 1974, the Company adopted an Electric Fossil Fuel Adjustment Clause ("EFAC") which provided for proper rate reflection of increases or decreases in fossil fuel production costs at Company-owned facilities and in the cost of energy purchased through the Pennsylvania-New Jersey-Maryland Interconnection. This clause worked reasonably well as long as coal and oil costs were

approximately equal and there was no nuclear generation. However, with the addition of nuclear power generation to the PECO system and with a growing price disparity between coal and oil prices, the mechanics of the EFAC resulted in a substantial and consistent under-recovery of energy costs for the Company.

On July 1, 1978, PECO and other electric utilities in Pennsylvania instituted the Energy Clause ("EC") which provided for recovery of all increases and decreases in the cost of fuel and energy produced, purchased or delivered. The Energy Clause recognized all sources of generation, including nuclear, and allowed for specific pricing of interchange transactions. The EC, like the EFAC, was a monthly adjustment factor calculated on the basis of historic data and applied prospectively with a billing lag of approximately two months.

Effective June 1, 1980, PECO adopted an Energy Cost Rate to recover changes in the Company's total energy costs. Unlike earlier fuel clauses, the ECR is prospective in nature and is calculated on the basis of estimated data. The ECR results in a charge or credit to the customer which, on a kilowatt-hour (kwh) basis, remains the same for a full twelve-month period. A copy of the Company's current ECR is attached as Schedule 1 to my testimony.

Q. Please describe how the current ECR is computed.

A. The ECR charge is computed annually and is then applied for a twelve-month period unless changed pursuant to mid-term revision procedures set forth in the tariff. The charge is developed by first estimating total energy costs for a prospective effective period. This estimate requires the Company to project a level of generation from each of its production plants and purchases from or sales to other utilities, as well as the anticipated cost of such power purchased or sold. From the total estimated unit cost of energy, i.e., the total cost of power from all sources divided by the total estimated kwh sales, there is deducted the unit cost of energy which will be recovered through base rates. The cost of energy either above or below the amount recovered in base rates is then further adjusted by experienced over/under collection of energy costs during the preceding Section 1307(e) year.

On July 1, 1980, the Company established 28.178 mills per kwh as the base cost of energy to be included in its base rates for electric service. This base cost has remained constant thereafter until the Company's current rate filing in which the Company proposes a 7.355 mill per kwh reduction in the base cost of energy to reflect anticipated energy cost savings from the operation of Limerick 1.

Q. Please explain the fundamental elements of the current ECR charge computation.

A. There are two such elements, which are referred to as the "E" factor and the "C" factor.

The "E" factor reflects prior period over/under collections and can be either a credit or a charge. It represents the difference between energy costs incurred during the "E" factor period and ECR revenues received during the same period. If costs exceeded revenues, an underrecovery occurs, which can be recouped during a prospective ECR application period as an additional charge included in the ECR computation. Conversely, if revenues exceeded costs, the "E" factor is a credit, and is refunded during the prospective period. The "E" factor period is the twelve months ending two months prior to the effective date of a new ECR charge. Under current practice, the ECR recalculation becomes effective April 1, and the "E" factor period therefore is the prior twelve months ending January 31.

The "C" factor is the amount by which total projected energy costs for a prospective twelve-month period divided by total prospective sales (kwh) exceed the cost of energy included in base rates. The "C" factor period is the twelve-month period commencing on the effective date of each annual recalculation of the ECR charge, i.e. April 1 under current ECR practice.

Q. Mr. Hill, what is the purpose of the ECR?

A. Fuel and energy expenses are the largest single operating expense category incurred by a utility in providing service to its customers. For instance, in 1984, this category of expense accounted for almost 45% of the total operating expenses including taxes and depreciation for the Company. Full and timely recovery of these expenses and a mechanism to insure such recovery is therefore essential to the financial viability of PECO.

In addition to their absolute magnitude, energy costs are subject to great variability due to a number of factors beyond PECO's control, and therefore are very difficult to project accurately, particularly over the short-term. For example, as explained more fully in Mr. Carroll's testimony (Statement 22A), PECO's generating and transmission facilities are interconnected with ten other electric utilities in a group collectively known as the Pennsylvania-New Jersey-Maryland ("PJM") Interconnection. Under the PJM Interconnection Agreement, energy flows freely among the member companies, and power is generated from the most economic of the approximately 500 generating units on the PJM system at any point in time regardless of the ownership of the unit. Thus, an important part of PECO's total energy cost projection for any 12-month period is an estimate of the amount of energy PECO will buy from and sell to PJM

members and the expected cost of that energy. Any changes from expectations in the operation of major PJM units will affect the Company's total energy costs. The Company's energy costs therefore are dependent not only on the performance of the Company's generating units, but also the performance characteristics of other units operating on the PJM over which PECO has no control. Since interchange costs accounted for approximately 53% of total fuel and interchange costs incurred by PECO in 1984, changes in forecasted interchange expense obviously will have a substantial impact on the Company's energy costs.

Moreover, since PJM is a multi-area power pool, there are transmission limitations on energy transfer within PJM. The Company's energy expense forecast takes these transmission limitations into consideration; however, if a member PJM company requires more interchange energy from outside PJM than projected, transmission limitations would reduce the amount of energy PECO is able to acquire from outside PJM and increase PECO's energy costs, through no fault of the Company.

Absolute changes in fuel prices also significantly affect energy costs and are beyond the Company's control. For example, during the oil embargo of 1974, there was a dramatic escalation in the price of oil due to world economic and political conditions. Similarly, coal prices

are based on the results of UMW contracts and short-term variations due to market conditions. Since fuel is purchased solely for the benefit of our customer's energy needs, these cost changes must be passed through in order to maintain the financial viability of the Company.

Changes in electric sales levels also impact PECO's energy costs. Energy requirements are calculated based on "normal" temperatures, weather and economic conditions. When temperature extremes are experienced, by PECO or on PJM (hotter than normal in summer or colder than normal in winter) or when economic growth is greater than expected in PECO's service territory or in the PJM system, there is a corresponding increase in customer energy usage. In order to meet these increased energy requirements, higher operating cost PECO generating units, i.e., oil-fired steam and combustion turbine peaking units, must be operated more frequently, and higher cost PJM energy must be purchased. This higher cost power production and purchases can substantially increase PECO's energy costs.

Regulatory constraints also play a large part in the cost and type of fuel PECO can burn. PECO has the strictest air quality control standards in Pennsylvania, including both the standards of the Environmental Protection Agency and the City of Philadelphia. The combination of these two agency standards require PECO to burn very low sulphur

content oil, which increases both the absolute cost and variability of this fuel. In addition, the Company's magnesium oxide facilities are required in order to meet strict air quality control standards at the Company's Philadelphia-area coal-fired units. If these facilities are not operational for any reason, PECO would be required to shut down these coal units. Similarly, NRC requirements, which are beyond PECO's control, have and could continue to affect the level of operations of PECO's nuclear units.

For the reasons set forth above, it is essential for both the Company and its customers that a mechanism be in place to ensure reasonable and timely recovery of energy expenses. Both the Pennsylvania Legislature and this Commission have recognized this need and have allowed for recovery and reconciliation of expenses through an automatic adjustment clause provided under Section 1307 of the Public Utility Code.

Q. Mr. Hill, you have discussed several variables which cause increases in PECO's total cost of energy. Could these same factors also cause decreased energy costs?

A. Yes. A decrease in fossil fuel prices, a decline in sales, and other factors could decrease PECO's energy costs. Under the existing ECR, the benefits of energy cost decreases are fully and automatically flowed through to ratepayers.

Q. Mr. Hill, has the Company performed any analyses to demonstrate the variability of its energy costs?

A. Yes. As explained in Mr. Carroll's testimony, the Company has performed two alternative scenario production cost model runs to demonstrate the potential variability of PECO's energy costs. The results of these analyses are set forth in the following table:

	Projected Total Fuel & Interchange Expenses (Million Dollars)		
	7/86 - 6/87	7/87 - 6/88	7/88-6/89
Base Case	$476.5	$532.9	$511.2
Scenario #1 - low coal generation	$585.4	$670.3	$648.0
Scenario #2 - low nuclear generation	$606.0	$674.2	$743.4

As explained in Mr. Carroll's testimony, the base case of $476.5 million is a reasonable estimate of total energy costs for the period July 1, 1986 - June 30, 1987. Scenario 1 adjusts the base case to reflect a reduction in output of PJM and PECO coal units, a reduction in two-party purchases from midwestern coal plants, low river hydroelectric output, and higher than expected fossil fuel price increases. Under this scenario, PECO's annual energy costs would increase by $108.9-$137.8 million. Scenario 2 is the same as Scenario 1 except that it assumes normal PJM and PECO coal generation, and normal hydroelectric output, but lower than expected

PECO and PJM nuclear generation. This Scenario would produce an increase of $129.5-$232.2 million in PECO's total annual energy costs.

Three points should be emphasized concerning these scenarios. First, as explained by Mr. Carroll, the adjustments made are attributable to events beyond PECO's control and are based upon either actual historic experience or events which could reasonably occur on the PJM system.

Second, as the absolute magnitude of energy costs increases over the three-year period of Mr. Carroll's study, the degree of variability also increases. Specifically, the range of variability increases from a first year level (July 1986 - June 1987) of $108.9-$129.5 million to $137.4-$141.3 million in year two and $136.8-$232.2 million in year three.

Finally, while the analyses performed reflect events which increase PECO's energy costs, similar events could occur which would <u>decrease</u> energy costs, and thereby result in an overrecovery of energy costs by the Company from customers in the absence of the current ECR.

Q. Please describe the potential impact of the above scenarios on the Company if an 80%/20% ECR were adopted.

A. Under an 80%/20% ECR, 20% of the energy cost increases described in the above scenarios would never be recovered even though they were reasonable and necessary costs incurred to provide service to customers and even though the

increases were caused by events beyond PECO's control. For Scenario 1 this would be a potential non-recovery of $21.8-$27.6 million, and $25.9-$46.4 million for Scenario 2. This impact of this non-recovery is obviously significant by any standard and is particularly disturbing for both the Company and its customers given the seriously substandard current financial condition of the Company as explained in Mr. Brennan's testimony.

Q. Mr. Hill, are the factors discussed above which cause uncontrolled variability of energy costs expected to continue into the future?

A. Yes. With respect to oil prices, on December 10, 1985, changes in OPEC production and pricing occurred which may have a significant impact on the future price of oil. The Company must now make its best estimate of what the future price of oil will be, at a time when there is great uncertainty as to the level of future oil prices.

With respect to unit operating performance, Mr. Gallagher has stated in his testimony that the Company has accomplished, and will continue to make improvements to its generating stations. These improvements have been reflected in the Company's energy cost projection. However, despite these improvements, it is likely that unforeseen outages will continue to occur on the Company's generating units and the same is true for other PJM generating units. Management

of these PJM companies do the best they can to accurately predict future outages on their generating units. However, no one has a crystal ball to precisely predict the future.

Also, weather conditions in PJM and the Company's service territories could deviate substantially from "normal" weather conditions, and the economy may be stronger or weaker than predicted. Finally, while the Company anticipates a reduction in new NRC requirements in the future, acid rain legislation or other legislative or regulatory action could significantly affect the operation of PJM coal and other base load units.

All of the above factors could significantly increase, as well as possibly decrease, the energy costs the Company actually experiences as compared to its best projections. Thus, factors such as the magnitude, variability, uncontrollability and financial impact of energy costs which gave rise to Commission adoption of the ECR remain valid today and continue to support an ECR mechanism which provides full and timely recovery of energy costs for the benefit of the Company and its customers.

Q. Mr. Hill, does the Company have existing incentives to supply the most reliable and economic power to meet its customers' needs?

A. Yes, the Company has several incentives to operate efficiently. As explained in Mr. Carroll's testimony, the

economic dispatch system operated by the Company and PJM ensures that customers are receiving the most economic power available at any point of time. In addition, the Company has a strong incentive to minimize rate levels to attract additional sales and to improve its competitive position with competing fuels and power sources. The Company must also satisfy the Commission by operating efficiently to meet various statutory and other requirements. The Commission's 1307(e) audit proceedings, management audits, rate cases and various investigation proceedings all help to ensure that the Company's ratepayers are receiving reliable energy at the lowest possible cost. Finally, PECO's management, as well as its entire workforce, have pride in the job that they do. Meeting customers' needs as economically, efficiently and safely as possible is a major corporate objective of PECO employees. Specific examples of the efforts PECO has undertaken and plans to undertake to improve its generating unit performance are addressed in Mr. Gallagher's testimony (Statement 30).

Q. Mr. Hill, based upon your testimony above and the testimony of Messrs. Carroll, Gallagher and Brennan, what is the Company's position regarding the 80%/20% ECR modification proposed by the Commission's Order?

A. We believe that the existing ECR has operated efficiently and equitably for both the Company and its customers and

should be retained in its present form. Energy costs are PECO's single largest expense and are subject to great and uncontrollable variability. The current ECR assures that the Company will recover its energy costs, no more or less, which is fair and equitable to ratepayers and shareholders. A failure to recover actual energy costs could have a significant adverse impact on the Company's already substandard financial condition. As explained by Mr Brennan, an ECR which allows full and timely cost recovery is important to the investment community, and the absence of such a mechanism could increase PECO's risk and its cost of capital to the ultimate detriment of customers. Moreover, PECO has existing incentives to control energy costs, and the Commission has the ability to review, investigate and disallow any energy costs which it believes are unreasonable.

Alternatively, should the Commission proceed to adopt an 80%/20% ECR, the Company believes that a reasonable limitation or "cap" on the amount of gain or loss on the 20% of energy cost variations not subject to after-the-fact reconciliation should be established for the following reasons:

1. A cap would at least partially reflect the fact that a utility's energy costs are highly variable and to a large extent uncontrollable, and the importance of full and

timely recovery of energy costs to a utility and its customers;

2. A cap would reflect the experimental nature of an 80%/20% ECR;

3. A cap would place a reasonable limitation on the gain PECO would receive in the event of lower than expected energy costs, and would give customers an opportunity to receive any gain in excess of the cap;

4. A cap would establish a reasonable limitation on the potential loss to PECO in the event of higher than expected energy costs, and as explained by Mr. Brennan, would be extremely important to the Company and its customers in limiting any increase in risk and capital costs resulting from the adoption of an 80%/20% ECR;

5. A cap would limit disruptive change in rates and therefore would be consistent with principles of gradualism;

6. A cap would be consistent with energy cost incentive programs established by other regulatory commissions, as explained by Mr. Brennan.

Q. What specific "cap" does the Company propose?

A. The "cap" should limit the annual gain or loss in energy cost recovery to $35 million in annual energy expense. The derivation and justification for this cap are set forth in Mr. Brennan's testimony.

Q. Mr. Hill, has the Company prepared a modified ECR to incorporate the 80%/20% provision discussed in the Commission October 30 Order?

A. Yes. Schedule 2 to my testimony contains a revised Energy Cost Rate Factor ("ECRF") to reflect the new 80%/20% ECR. Specifically, the definition of the "E" factor in the ECRF has been changed such that it will include only 80% of the over/under collections from the applicable "E" factor period subject to the $35 million cap.

Q. Mr. Hill, has the Company also prepared a revised ECR calculation for the first year rates set in the Limerick 1 rate proceeding will be in effect?

A. Yes. Schedule 3 is the Company's preliminary calculation of a revised ECR for an approximate twelve-month period beginning June 27, 1986 until June 30, 1987. The proposed effective date of June 27, 1986 reflects the end of the suspension period in this proceeding since the ECRF revision should occur concurrently with the effective date of the new rates established by the Commission in its final Order in this proceeding. After the first year, subsequent ECRF calculations will be effective for a 12-month period beginning July 1. Except for the change in time period, the filing in Schedule 3 is the standard ECR filing which the Company presents to the Commission annually. The projected energy costs in the filing are those developed and presented

in Mr. Carroll's additional direct testimony. It should be noted that this filing is preliminary in that it is based upon an estimate of the Company's ECR No. 10 filing which will become effective on April 1, 1986, and an estimate of over/under collections for the 15-month period ending April 30, 1986.

Q. Mr. Hill, how will the Company make the transition from the current ECR mechanism to the ECRF?

A. The Company will file its revised ECR calculation by March 1, 1986, to be effective April 1, 1986, employing existing ECR procedures. Specifically, this filing will reflect expected energy costs for April 1, 1986 - March 31, 1987 (but excluding Limerick 1) and full reconciliation of actual over/under collections for the twelve months ended January 31, 1986. However, this ECR will only be in effect for approximately three months, i.e., until June 27, 1986, when base rates reflecting Limerick 1 are effective. The new ECRF will take effect coincident with the effective date of new base rates reflecting Limerick 1, i.e., on or about June 27, 1986. The "C" factor in this ECRF will reflect anticipated energy costs to be incurred during the period June 27, 1986 - June 30, 1987 (including Limerick 1), and an updated "E" factor for the fifteen-month period ended April 30, 1986. This "E" factor will reflect 100% refund or recoupment of over/under collection in accordance with ECR procedures in effect during that period.

Q. When and how will the 80%/20% split, if approved by the Commission, be reflected in the ECRF "E" factor calculation?

A. The ECRF for the period July 1, 1987 - June 30, 1988 will be based upon an "E" factor period of May 1, 1986 - April 30, 1987, reflecting the normal two-month lag in ECRF year and "E" factor year. This "E" factor will reflect 100% refund/recoupment for the period May 1, 1986 - June 26, 1986 in accordance with established ECR procedures for that period, and 80% refund/recoupment for the June 27, 1986 - April 30, 1987 period in accordance with the new 80%/20% procedure which may become effective at the end of this case.

Q. Mr. Hill, will the filing of the ECRF affect the Company's proposal to reduce the cost of fuel included in base rates to reflect anticipated energy savings from the operation of Limerick 1?

A. No, such a charge is not necessary or appropriate. The proposed 7.355 mill/kwh roll-out of base energy costs represents a reasonable estimate of the average annual energy cost reductions associated with Limerick 1 during the first two years new base rates will be in effect. Since the base rates filed by the Company reflect the capital and operating costs associated with Limerick 1, it is also appropriate to adjust the cost of energy in base rates to reflect the average energy cost savings from Limerick 1

during the initial period new base rates will be in effect. The Company's proposed 7.355 mill/kwh roll-out achieves this result.

The changes proposed by the Company in response to the Commission's October 30 Order deal solely with the Company's ECR and have no impact on base rates or the cost of fuel reflected in base rates. There is therefore no need to revise the base rate filing to reflect proposed revisions to the Company's ECR.

Moreover, it should be noted that the level of fuel costs included in base rates will have no impact on the operation of the 80%/20% ECR procedure since the 80%/20% split applies to all energy costs, including the base cost of fuel. Similarly, in accordance with the Commission's October 30 Order, the total energy costs reflected in the customer's bill (base cost of fuel and ECR) will be stated as one amount on the customer's bill. Therefore, the relative level of energy costs in base rates and the ECR will not affect the level of energy costs shown on the customer's bill.

Finally, the Company's cost of service study (Exhibit WFS-1), allocation of the proposed revenue increase, rate design, and phase-in calculations are all based upon the proposed 7.355 mill/kwh reduction to the base cost of fuel. A change in this roll-out would require the complete

recalculation of each of these items, and would be burdensome and unnecessary for the reasons set for the above.

Q. Mr. Hill, does this complete your further supplemental direct testimony?

A. Yes, it does.

Schedule 1

ENERGY COST RATE

An energy cost rate shall be applied to each kilowatt-hour supplied under this tariff. This energy cost rate will be determined to the nearest one-thousandth of one mill per kilowatt-hour in acccordance with the formula set forth below and shall be applied to all kilowatt-hours billed during the billing month.

$$ECR = \left\{ \frac{F}{S_t} - B - \frac{E}{S_a} \right\} X \frac{1}{1 - T}$$

The energy cost rate so computed shall be applied to customers' bills for a one-year period during the billing periods of April through March. The Company's proposed annual energy cost rate shall be submitted to the Commission by March 1 of each year and this proposed rate shall become effective for service rendered on or after the following April 1 unless otherwise ordered by the Commission. However, such rate may be revised if the then effective rate is estimated to result in a net over or under collection such that the E for the current twelve-month period ending January 31 will have an absolute value greater than $10 million. Such revision shall become effective 30 days from the date of the revised filing unless otherwise ordered by the Commission.

Where ECR = Energy cost rate in mills per kilowatt-hour to be applied to each kilowatt-hour supplied under this tariff.

F = The estimated energy-related cost of net energy generated in the Company's fossil and nuclear generating stations, excluding the cost of energy generated and sold to other utilities on a firm basis, plus the Company's energy-related cost of energy purchased and net energy interchanged plus the assigned test power costs for the computation year, defined as follows:

Fossil Generation - the costs charged to fuel Accounts 501 and 547 which are computed on basis of the cost of fuel delivered to the generating site at which it is consumed, plus the cost of disposing of solid waste from sulfur oxide removal devices.

Nuclear Generation - the costs charged to fuel Accounts 518 and 521 which are computed on the basis of the costs of such fuel delivered at the generating site at which it is consumed after deducting therefrom the present salvage or reuse value of such fuel.

Net Energy Purchases - the amounts charged or credited to Account 555, excluding demand charges other than those associated with agreements for the purchase of energy at a cost (including associated demand charges) that is less than the cost of obtaining energy from alternative sources.

Net Energy Interchanged - the amounts charged or credited to Account 555, excluding charges or credits for demand related costs.

Test Power - the amounts charged to Account 557 for the value assigned to the energy produced from facilities undergoing operational tests prior to being placed into commercial operation.

The computation year shall be April 1 through March 31 for which the ECR as computed will apply. In projecting the Company's energy costs for the computation year, the estimated cost of energy generated and sold to other utilities on a firm basis and the estimated net effect on the Company's energy costs of generation forecast for the computation year from any unit whose costs are not currently reflected in base rates shall be excluded. When the in-service date of such a unit can be estimated with reasonable certainty, the Company shall file with the Commission no later than 30 days prior to the unit's expected in-service date for an interim revision of the ECR then in effect to reflect the estimated effect of the unit's operation on the Company's energy costs. Such interim revision of the ECR shall not become effective unless and until rates reflecting the unit's base rate revenue requirements become effective by order of the Commission. (C)

(C) Indicates change.

ENERGY COST RATE-Continued

E = Experienced net over or under collection of the cost of energy as of the end of the twelve-month period ending with the preceding January billing period including interest. Interest shall be computed monthly at the appropriate rate as provided in Section 1308(d) of the Public Utility Code from the month the over or under collection occurs to the effective month such over collection is refunded and such under collection is recouped. Customer shall not be liable for interest on net under collections.

S_t = The Company's projected total kilowatt-hour sales to the customers excluding firm sales to other utilities during the computation year.

S_a = The Company's kilowatt-hour sales to which the energy cost rate applies, projected for the computation year.

B = Base energy cost of 28.178 mills per kilowatt-hour.

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in decimal form.

Minimum bills shall not be reduced by reason of this energy cost rate. This rate shall be applied to all kilowatt-hours supplied and such charge shall be in addition to any minimum applicable.

The Company shall file quarterly reports within thirty (30) days following the conclusion of each computation year quarter. These reports will be in such form as the Commission shall have prescribed. The third quarter report shall be accompanied by a tentative estimate of the energy cost rate for the next computation year.

The application of the energy cost rate shall be subject to continuous review and to audit by the Commission at such intervals as the Commission shall determine. The Commission shall continuously review the reasonableness and lawfulness of the amounts of the charges produced by the energy cost rate and the charges included herein.

If from such audit it shall be determined, by final order entered after notice and hearing, that this energy cost rate has been erroneously or improperly utilized, the Company will rectify such error or impropriety, and in accordance with the terms of the order, apply credits against future energy cost rates for such revenues as shall have been erroneously or improperly collected. The Commission's order shall be subject to the right of appeal.

Schedule 2

ENERGY COST RATE FACTOR

All kilowatt-hours supplied under this tariff shall include an energy cost rate factor as determined by the formula below. This energy cost rate factor will be determined to the nearest one-thousandth of one mill per kilowatt-hour in acccordance with the formula set forth below and shall be applied to all kilowatt-hours billed during the billing month.

$$ECRF = \left[\frac{F}{S_t} - B - \frac{E}{S_a} \right] X \frac{1}{1 - T}$$

The energy cost rate factor so computed shall be applied to customers' bills for a one-year period during the billing periods of July through June except that the first application period will be for the billing periods of June 27, 1986 through June 30, 1987. The Company's proposed annual energy cost rate factor shall be submitted to the Commission by June 1 of each year and this proposed factor shall become effective for service rendered on or after the following July 1 unless otherwise ordered by the Commission.

Where ECRF = Energy cost rate factor in mills per kilowatt-hour to be applied to each kilowatt-hour supplied under this tariff.

F = The estimated energy-related cost of net energy generated in the Company's fossil and nuclear generating stations, excluding the cost of energy generated and sold to other utilities on a firm basis, plus the Company's energy-related cost of energy purchased and net energy interchanged plus the assigned test power costs for the computation year, defined as follows:

Fossil Generation - the costs charged to fuel Accounts 501 and 547 which are computed on basis of the cost of fuel delivered to the generating site at which it is consumed, plus the cost of disposing of solid waste from sulfur oxide removal devices.

Nuclear Generation - the costs charged to fuel Accounts 518 and 521 which are computed on the basis of the costs of such fuel delivered at the generating site at which it is consumed after deducting therefrom the present salvage or reuse value of such fuel.

Net Energy Purchases - the amounts charged or credited to Account 555, excluding demand charges other than those associated with agreements for the purchase of energy at a cost (including associated demand charges) that is less than the cost of obtaining energy from alternative sources.

Net Energy Interchanged - the amounts charged or credited to Account 555, excluding charges or credits for demand related costs.

Test Power - the amounts charged to Account 557 for the value assigned to the energy produced from facilities undergoing operational tests prior to being placed into commercial operation.

The first computation year shall be June 27, 1986 through June 30, 1987, and thereafter shall be July 1 through June 30, for which the ECRF as computed will apply. In projecting the Company's energy costs for the computation year, the estimated cost of energy generated and sold to other utilities on a firm basis and the estimated net effect on the Company's energy costs of generation forecast for the computation year from any unit whose costs are not currently reflected in base rates shall be excluded. When the in-service date of such a unit can be estimated with reasonable certainty, the Company shall file with the Commission no later than 30 days prior to the unit's expected in-service date for an interim revision of the ECRF then in effect to reflect the estimated effect of the unit's operation on the Company's energy costs. Such interim revision of the ECRF shall not become effective unless and until rates reflecting the unit's base rate revenue requirements become effective by order of the Commission.

0590G-31

ENERGY COST RATE FACTOR - Continued

E = Experienced net over or under collection of the cost of energy determined as follows: Effective June 27, 1986 the Company will reconcile for refund with interest or recovery without interest only 80% of post June 26, 1986 experienced net over or under collection of the cost of energy. The first "E" factor time period will be for the fifteen months ending with the April 1986 billing period with 100% of the experienced net over or under collections reconciled. The second "E" factor time period will be for the twelve months ending with the April 1987 billing period with 100% of the experienced net over or under collections reconciled through June 26, 1986 and 80% of net over or under collections reconciled from June 27, 1986 through April 1987. All subsequent "E" factor periods will be based upon an 80% reconciliation of experienced net over or under collections for a twelve-month period ending with the preceding April billing period. If the 20% of net over or under collections of energy costs, not subject to reconciliation, exceeds an absolute dollar amount of $35 million in any one "E" factor period, the over or under collection in excess of $35 million shall be included in the "E" factor reconciliation. Interest shall be computed monthly at the appropriate rate as provided in Section 1308(d) of the Public Utility Code from the month the over or under collection occurs to the effective month such over collection is refunded and such under collection is recouped. Interest will only be paid on net over- collections subject to reconciliation. Customer shall not be liable for interest on net undercollections.

S_t= The Company's projected total kilowatt-hour sales to the customers excluding firm sales to other utilities during the computation year.

S_a= The Company's kilowatt-hour sales to which the energy cost rate factor applies, projected for the computation year.

B = Base energy cost of 20.823 mills per kilowatt-hour.

T = The Pennsylvania gross receipts tax rate in effect during the billing month expressed in decimal form.

Minimum bills shall not be reduced by reason of this energy cost rate factor. This factor shall be applied to all kilowatt-hours supplied and such charge shall be in addition to any minimum applicable.

The Company shall file quarterly reports within thirty (30) days following the conclusion of each computation year quarter. These reports will be in such form as the Commission shall have prescribed. The third quarter report shall be accompanied by a tentative estimate of the energy cost rate factor for the next computation year.

The application of the energy cost rate factor shall be subject to continuous review and to audit by the Commission at such intervals as the Commission shall determine. The Commission shall continuously review the reasonableness and lawfulness of the amounts of the charges produced by the energy cost rate factors and the charges included herein.

If from such audit it shall be determined, by final order entered after notice and hearing, that this energy cost rate factor has been erroneously or improperly utilized, the Company will rectify such error or impropriety, and in accordance with the terms of the order, apply credits against future energy cost rate factors for such revenues as shall have been erroneously or improperly collected. The Commission's order shall be subject to the right of appeal.

0590G-31

Schedule 3

STATEMENT NO. 1

ENERGY COST RATE FACTOR

Preliminary

Energy Cost Rate Factor Applicable to Service
Rendered on June 27, 1986 and Thereafter*

Credit: ..... (3.076) mills per kilowatt-hour
or
($0.003076) per kilowatt hour

*Use prior to June 27, 1986 will be billed under Energy Cost Rate No. 10

PHILADELPHIA ELECTRIC COMPANY

J. H. AUSTIN, JR., President

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-1
Sheet 1 of 1

PHILADELPHIA ELECTRIC COMPANY

Computation of Energy Cost Rate Factor
Application Period: June 27, 1986 through June 1987
Computation Period: June 27, 1986 through June 1987

1. Energy Cost Rate Factor = $\left(\frac{F}{S_t} - B - \frac{E}{S_a}\right) \times \frac{1}{1-T}$

2. F = Cost of Energy (Schedule E-2, Sheet 2 of 3) $476,536,383

3. E = Experienced Net Under-Collection (Sch. E-4, 5 of 5) ..... ($37,110,868)

4. S_t = Projected Sales for Comp. Period (Sch. E-2, Sh 3 of 3) ..... 28,765,030 MWh

5. S_a = Proj. Retail Sales For Comp. Period (Sch. E-2, Sh 3 of 3) ... 28,151,668 MWh

6. $\frac{F}{S_t} - \frac{E}{S_a}$ Projected Cost per kWh ..... 17.885 m/kWh

7. B = Base Cost ..... - 20.823 m/kWh

8. Excess Cost (Line 6 - Line 7) ..... (2.938) m/kWh

9. $\frac{1}{1-T}$ (T = 4.5%) ..... x 1.04712

10. Energy Cost Rate Factor - Calculated (Line 8 x Line 9) ..... (3.076) m/kWh

December 30, 1985
0034/79H

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-2
Sheet 1 of 3

ELECTRIC GENERATION AND FUEL COST ESTIMATES

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
MWH						
OIL-PE STM.	153,000	146,000	146,000	114,000	146,000	186,000
COAL-PE STM.	269,000	316,000	204,000	200,000	185,000	220,000
COAL-MINEMTH	372,000	374,000	365,000	383,000	336,000	339,000
INT.COMB.	17,220	32,910	14,980	7,590	7,810	4,240
TOTAL FOSSIL	811,220	868,910	729,980	704,590	674,810	749,240
MWH NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
NET HYDRO	24,000	(7,000)	1,000	49,000	76,000	144,000
OTHER	0	0	0	0	0	0
RECEIVED PJM	234,000	213,000	301,000	182,000	295,000	294,000
DELIV'D PJM	(128,000)	(174,000)	(95,000)	(80,000)	(104,000)	(90,000)
STEAM-HT PP	500	2,500	2,700	3,900	8,500	16,500
ME,PPL & DPL	16	16	16	16	16	16
2PARTY TRANS	173,000	175,000	174,000	191,000	192,000	208,000
INTCH & PUR	279,516	216,516	382,716	296,916	391,516	420,516
TOTAL OUTPUT	2,864,414	2,798,423	2,462,148	2,344,868	2,385,407	2,621,360
$						
OIL-PE STM	8,291,000	7,906,000	8,068,000	6,730,000	8,006,000	10,020,000
COAL-PE STM	5,537,000	6,504,000	4,206,000	4,175,000	3,884,000	4,661,000
MINEMOUTH	5,202,000	5,272,000	5,168,000	5,460,000	4,804,000	4,897,000
INT.COMB	1,128,000	2,168,800	966,400	475,500	493,500	262,500
TOTAL FOSSIL	20,158,000	21,850,800	18,408,400	16,840,500	17,187,500	19,840,500
(NUCLEAR EXCLUDING INTEREST, BUT INCLUDING OIL)						
NUCLEAR.	12,899,724	12,713,952	10,067,749	9,915,663	9,442,991	9,990,157
OTHER	0	0	0	0	0	0
RECEIVED PJM	7,014,000	7,470,000	9,825,000	7,172,000	9,080,000	10,142,000
DELIV'D PJM	(5,636,000)	(7,447,000)	(4,149,000)	(3,135,000)	(5,235,000)	(4,695,000)
STEAM-HT PP	17,000	87,000	96,000	142,000	307,000	646,000
ME,PPL & DPL	1,196	1,196	1,196	1,196	1,196	1,196
2PARTY TRANS	5,225,000	5,295,000	5,261,000	5,891,000	5,921,000	6,394,000
INTCH & PUR	6,621,196	5,406,196	11,034,196	10,071,196	10,074,196	12,488,196
$-FIN.CHGS	39,678,920	39,970,948	39,510,345	36,827,359	36,704,687	42,318,853
(GAS $ INCLUDED IN COAL-PE STM)						
TOTAL GAS	537,000	632,000	357,000	317,000	108,000	0

DEC 88 [illegible]

ELECTRIC GENERATION AND FUEL COST ESTIMATES

MWH	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
OIL-PE STM.	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
COAL-PE STM.	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
COAL-MINEMTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
INT.COMB.	11,770	12,380	2,610	12,280	2,240	4,230	130,260
TOTAL FOSSIL	1,005,770	760,380	715,610	668,280	739,240	743,230	9,171,260
MWH NUCLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
NET HYDRO	99,000	131,000	213,000	225,000	160,000	79,000	1,194,000
OTHER	0	0	0	0	0	0	0
RECEIVED PJM	136,000	282,000	259,000	418,000	387,000	725,000	3,726,000
DELIV'D PJM	(336,000)	(113,000)	(148,000)	(14,000)	(23,000)	(4,000)	(1,317,000)
STEAM-HT PP	22,200	15,600	12,100	5,100	1,900	2,300	93,800
ME,PPL & DPL	16	16	16	16	16	16	192
2PARTY TRANS	187,000	166,000	172,000	156,000	141,000	144,000	2,079,000
INTCH & PUR	9,216	350,616	295,116	565,116	506,916	867,316	4,581,992
TOTAL OUTPUT	2,729,324	2,436,967	2,506,516	2,261,193	2,321,348	2,554,526	30,286,494
$							
OIL-PE STM	15,134,000	8,923,000	6,507,000	5,958,000	4,788,000	7,531,000	97,862,000
COAL-PE STM	7,667,000	5,975,000	6,435,000	5,811,000	5,670,000	5,412,000	65,937,000
MINEMOUTH	5,329,000	4,578,000	4,283,000	4,260,000	5,848,000	5,230,000	60,331,000
INT.COMB	801,000	807,700	169,800	860,000	148,000	292,000	8,573,200
TOTAL FOSSIL	28,931,000	20,283,700	17,394,800	16,889,000	16,454,000	18,465,000	232,703,200
(NUCLEAR EXCLUDING INTEREST, BUT INCLUDING OIL)							
NUCLEAR.	12,152,686	9,143,637	9,859,519	5,990,617	6,791,025	6,357,607	115,325,327
OTHER	0	0	0	0	0	0	0
RECEIVED PJM	5,123,000	11,222,000	8,415,000	12,257,000	11,702,000	23,748,000	123,170,000
DELIV'D PJM	(17,798,000)	(6,301,000)	(6,655,000)	(764,000)	(725,000)	(237,000)	(62,777,000)
STEAM-HT PP	1,006,000	656,000	434,000	173,000	60,000	78,000	3,702,000
ME,PPL & DPL	1,280	1,280	1,280	1,280	1,280	1,280	14,856
2PARTY TRANS	5,852,000	5,199,000	5,392,000	4,939,000	4,471,000	4,558,000	64,398,000
INTCH & PUR	(5,815,720)	10,777,280	7,587,280	16,606,280	15,509,280	28,148,280	128,507,856
$-FIN.CHGS	35,267,966	40,204,617	34,841,599	39,485,897	38,754,305	52,970,887	476,536,383
(GAS $ INCLUDED IN COAL-PE STM)							
TOTAL GAS	0	0	41,000	596,000	586,000	485,000	3,659,000

DEC 30 1985

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-2
Sheet 2 of 3

Philadelphia Electric Company
System Sales - MWH
Estimated 4/1/86 - 3/31/87

Month	Retail (PECo) (1)	Resale (PECo Plus Interdepartment) (2)	Resale (SE to CP) (3)	Total Projected Sales (4)=(1)+(2)+(3)
July 1986	2,198,414	39,904	6,400	2,244,718
August	2,065,014	38,101	6,400	2,109,515
September	2,241,014	39,103	6,500	2,286,617
October	2,512,014	46,307	7,900	2,566,221
November	2,552,814	45,602	7,200	2,605,616
December	2,498,814	38,705	5,900	2,543,419
January 1987	2,196,814	42,503	7,300	2,246,617
February	2,098,714	38,306	7,500	2,144,520
March	2,389,114	51,410	9,100	2,449,624
April	2,584,214	53,157	9,950	2,647,321
May	2,498,614	44,577	8,430	2,551,621
June	2,316,114	44,477	8,630	2,369,221
12- Month Total	28,151,668	522,152	91,210	28,765,030

December 30, 1985
0034/79H

ECR FILING - 7/86 - 6/89

DISTRIBUTION 1 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
EHEAT OIL						
YLKILL#1	25,000	21,000	24,000	5,000	22,000	22,000
STONE#3	48,000	33,000	40,000	41,000	34,000	42,000
STONE#4	43,000	51,000	50,000	36,000	32,000	30,000
BY#2	0	0	0	0	40,000	53,000
NARE#7	20,000	20,000	17,000	19,000	17,000	20,000
NARE#8	17,000	21,000	15,000	13,000	1,000	19,000
R H OIL	153,000	146,000	146,000	114,000	146,000	186,000
ARGINAL OIL						
MOND#9	0	0	0	0	0	0
HARK#1	0	0	0	0	0	0
HARK#2	0	0	0	0	0	0
ARG OIL	0	0	0	0	0	0
T & MARGINAL OIL						
IL	153,000	146,000	146,000	114,000	146,000	186,000
AL						
STONE#1	104,000	118,000	115,000	129,000	121,000	106,000
STONE#2	115,000	139,000	30,000	0	0	40,000
Y#1	50,000	59,000	59,000	71,000	64,000	74,000
OAL	269,000	316,000	204,000	200,000	185,000	220,000
. AREA OIL AND COAL.						
STEAM	422,000	462,000	350,000	314,000	331,000	406,000
- STATION TOTALS						
TONE	310,000	341,000	235,000	206,000	187,000	218,000
Y	50,000	59,000	59,000	71,000	104,000	127,000
ARE7&8	37,000	41,000	32,000	32,000	18,000	39,000
HARK1&2	0	0	0	0	0	0

DEC 30 1985

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 1 of 24

ECR FILING - 7/86 - 6/89

MWH DISTRIBUTION 1 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
OIL							
PE REHEAT OIL							
SCHUYLKILL#1	45,000	24,000	21,000	14,000	9,000	14,000	246,000
EDDYSTONE#3	67,000	18,000	12,000	24,000	16,000	37,000	412,000
EDDYSTONE#4	66,000	62,000	13,000	12,000	20,000	20,000	435,000
CROMBY#2	44,000	12,000	44,000	32,000	25,000	38,000	288,000
DELAWARE#7	34,000	19,000	12,000	10,000	3,000	12,000	203,000
DELAWARE#8	21,000	21,000	11,000	10,000	5,000	11,000	165,000
MWH R H OIL	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
PE MARGINAL OIL							
RICHMOND#9	0	0	0	0	0	0	0
SOUTHWARK#1	0	0	0	0	0	0	0
SOUTHWARK#2	0	0	0	0	0	0	0
MWH MARG OIL	0	0	0	0	0	0	0
REHEAT & MARGINAL OIL							
MWH OIL	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
PE COAL							
EDDYSTONE#1	124,000	111,000	108,000	117,000	110,000	101,000	1,364,000
EDDYSTONE#2	147,000	98,000	133,000	126,000	130,000	97,000	1,055,000
CROMBY#1	84,000	68,000	55,000	28,000	24,000	53,000	689,000
MWH COAL	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
PHILA. AREA OIL AND COAL.							
PHILA STEAM	632,000	433,000	409,000	373,000	342,000	383,000	4,857,000
MEMO - STATION TOTALS							
EDDYSTONE	404,000	289,000	266,000	279,000	276,000	255,000	3,266,000
CROMBY	128,000	80,000	99,000	60,000	49,000	91,000	977,000
DELAWARE7&8	55,000	40,000	23,000	20,000	8,000	23,000	368,000
SOUTHWARK1&2	0	0	0	0	0	0	0

DEC 30 1985

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 2 of 24

ECR FILING - 7/86 - 6/89

MWH DISTRIBUTION 2 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
MINEMOUTH (PE SHARE)						
KEYSTONE#1	107,000	108,000	95,000	109,000	94,000	90,000
KEYSTONE#2	96,000	84,000	88,000	96,000	85,000	90,000
KEYSTONE STA	203,000	192,000	183,000	205,000	179,000	180,000
CONEMAUGH#1	81,000	96,000	87,000	86,000	79,000	85,000
CONEMAUGH#2	88,000	86,000	95,000	92,000	78,000	74,000
CONEMAUGHSTA	169,000	182,000	182,000	178,000	157,000	159,000
MINEMOUTH	372,000	374,000	365,000	383,000	336,000	339,000
PHILA. AREA OIL & COAL, AND MINEMOUTH COAL.						
FOSSIL STEAM	794,000	836,000	715,000	697,000	667,000	745,000
NUCLEAR (PE SHARE)						
PEACH BOT#2	258,117	281,339	252,759	216,140	290,270	208,102
PEACH BOT#3	229,561	272,658	206,693	188,222	132,811	266,502
PCH BOT STA	487,678	553,997	459,452	404,362	423,081	474,604
SALEM#1	282,000	264,000	242,000	247,000	274,000	247,000
SALEM#2	317,000	273,000	136,000	0	0	21,000
SALEM STA	599,000	537,000	378,000	247,000	274,000	268,000
LIM1	663,000	629,000	511,000	643,000	546,000	565,000
LIM2	0	0	0	0	0	0
LIM STA	663,000	629,000	511,000	643,000	546,000	565,000
MWH NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
OTHER (PRECOMMERCIAL)						
LIMERICK 1	0	0	0	0	0	0
LIMERICK 2	0	0	0	0	0	0
OTHER	0	0	0	0	0	0

DEC 30 1985

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 3 of 24

ECR FILING - 7/86 - 6/89

MNH DISTRIBUTION 2 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
MINEMOUTH (PE SHARE)							
KEYSTONE#1	93,000	90,000	111,000	21,000	84,000	101,000	1,103,000
KEYSTONE#2	81,000	81,000	94,000	92,000	107,000	92,000	1,086,000
KEYSTONE STA	174,000	171,000	205,000	113,000	191,000	193,000	2,189,000
CONEMAUGH#1	96,000	82,000	93,000	67,000	102,000	86,000	1,060,000
CONEMAUGH#2	92,000	62,000	6,000	83,000	102,000	77,000	935,000
CONEMAUGHSTA	188,000	144,000	99,000	170,000	204,000	163,000	1,995,000
MINEMOUTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
PHILA. AREA OIL & COAL, AND MINEMOUTH COAL. FOSSIL STEAM	994,000	748,000	713,000	656,000	737,000	739,000	9,041,000
NUCLEAR (PE SHARE)							
PEACH BOT#2	276,873	14,290	0	0	248,293	275,980	2,322,163
PEACH BOT#3	259,465	228,681	237,790	246,797	156,899	0	2,426,079
PCH BOT STA	536,338	242,971	237,790	246,797	405,192	275,980	4,748,242
SALEM#1	263,000	257,000	283,000	281,000	300,000	287,000	3,227,000
SALEM#2	255,000	209,000	207,000	275,000	210,000	302,000	2,205,000
SALEM STA	518,000	466,000	490,000	556,000	510,000	589,000	5,432,000
LIM1	561,000	486,000	555,000	0	0	0	5,159,000
LIM2	0	0	0	0	0	0	0
LIM STA	561,000	486,000	555,000	0	0	0	5,159,000
MNH NUCLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
OTHER (PRECOMMERCIAL)							
LIMERICK 1	0	0	0	0	0	0	0
LIMERICK 2	0	0	0	0	0	0	0
OTHER	0	0	0	0	0	0	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 4 of 24

ECR FILING - 7/86 - 6/89

ISTRIBUTION 3 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
LS						
Y D 1&2	20	0	0	0	100	40
ARE D	20	20	0	20	40	0
HARK D	0	0	0	0	0	0
LKILL D	0	0	20	10	0	0
ESELS	40	20	20	30	140	40
ONE D	10	20	20	0	0	0
AUGH D	10	20	20	0	0	0
L	60	60	60	30	140	40
URBINES						
GE CT	2,750	6,170	2,240	1,060	1,770	0
NE CT	0	0	0	0	0	0
HO CT	0	0	0	0	0	0
T TOTAL	2,750	6,170	2,240	1,060	1,770	0
HARK CT	210	870	400	0	0	0
TONE CT	280	880	360	0	0	0
ARE CT	270	830	400	0	0	0
LKILLCT	110	480	100	0	0	0
ER CT	210	630	300	0	0	0
S CT	360	790	360	0	0	0
R CT	240	840	330	0	0	0
MTG CT	0	0	0	0	0	0
BTOTAL	4,430	11,490	4,490	1,060	1,770	0
DON	12,700	21,300	10,400	6,500	5,900	4,200
TURBINES	17,130	32,790	14,890	7,560	7,670	4,200
H CT	30	60	30	0	0	0
L CT	17,160	32,850	14,920	7,560	7,670	4,200
L CT AND DIESEL						
L IC	17,220	32,910	14,980	7,590	7,810	4,240
LE CYCLE (INC. SALEM CT)						
OTAL	4,460	11,550	4,520	1,060	1,770	0

DEC 30 1986

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 5 of 24

ECR FILING - 7/86 - 6/89

DISTRIBUTION 3 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
SELS							
BY D 1&2	0	60	10	0	0	0	230
AHARE D	170	40	0	60	0	0	370
THHARK D	0	0	0	0	0	0	0
YLKILL D	40	0	0	0	0	0	70
IESELS	210	100	10	60	0	0	670
STONE D	0	0	0	10	0	0	60
EMAUGH D	0	0	0	10	0	0	60
SEL	210	100	10	80	0	0	790
TURBINES							
GE CT	860	280	0	2,830	240	930	19,130
NE CT	0	0	0	0	0	0	0
NO CT	0	0	0	0	0	0	0
CT TOTAL	860	280	0	2,830	240	930	19,130
THHARK CT	0	0	0	120	0	0	1,600
STONE CT	0	0	0	150	0	0	1,670
HARE CT	0	0	0	330	0	0	1,830
YLKILLCT	0	0	0	30	0	0	720
TER CT	0	0	0	180	0	0	1,320
S CT	0	0	0	220	0	0	1,730
R CT	0	0	0	210	0	0	1,620
MTG CT	0	0	0	0	0	0	0
BTOTAL	860	280	0	4,070	240	930	29,620
DON	10,700	12,000	2,600	8,100	2,000	3,300	99,700
TURBINES	11,560	12,280	2,600	12,170	2,240	4,230	129,320
1 CT	0	0	0	30	0	0	150
L CT	11,560	12,280	2,600	12,200	2,240	4,230	129,470
L CT AND DIESEL							
L IC	11,770	12,380	2,610	12,280	2,240	4,230	130,260
LE CYCLE (INC. SALEM CT)							
TAL	860	280	0	4,100	240	930	29,770

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 6 of 24

DEC 30 1985

L COST 1 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
(NO.6 & NO. 2)						
JVLKILL#1	1,146,000	936,000	1,122,000	227,000	1,015,000	1,059,000
/STONE1&2	182,000	166,000	186,000	195,000	164,000	210,000
/STONE3&4	5,185,000	4,852,000	5,147,000	4,643,000	4,086,000	4,460,000
1,2,3,4	5,367,000	5,018,000	5,333,000	4,838,000	4,250,000	4,670,000
(SULFUR)	0	0	0	0	224,000	424,000
/STONE	5,367,000	5,018,000	5,333,000	4,838,000	4,474,000	5,094,000
BY#1	16,000	14,000	14,000	11,000	11,000	10,000
BY#2	35,000	35,000	34,000	36,000	1,800,000	2,364,000
(SULFUR)	135,000	160,000	159,000	198,000	178,000	205,000
BY	186,000	209,000	207,000	245,000	1,989,000	2,579,000
HARE 7&8	1,727,000	1,903,000	1,565,000	1,618,000	930,000	1,917,000
MOND	0	0	0	0	0	0
THWARK1&2	0	0	0	0	0	0
L OIL	8,426,000	8,066,000	8,227,000	6,928,000	8,408,000	10,649,000
/STONE#1	1,880,000	2,122,000	2,086,000	2,376,000	2,222,000	1,956,000
/STONE#2	2,090,000	2,533,000	553,000	0	0	750,000
/STONE	3,970,000	4,655,000	2,639,000	2,376,000	2,222,000	2,706,000
BY#1	895,000	1,057,000	1,051,000	1,284,000	1,152,000	1,326,000
L PECOAL	4,865,000	5,712,000	3,690,000	3,660,000	3,374,000	4,032,000
FOR SCRUBBER						
STONE#1	256,000	290,000	282,000	317,000	108,000	0
STONE#2	281,000	342,000	75,000	0	0	0
L GAS	537,000	632,000	357,000	317,000	108,000	0
L OIL, TOTAL COAL & TOTAL GAS						
A STEAM	13,828,000	14,410,000	12,274,000	10,905,000	11,890,000	14,681,000

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 7 of 24

EC 30 1986

L COST 1 OF 4

(NO.6 & NO. 2)	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
JYLKILL#1	2,173,000	1,181,000	1,032,000	689,000	463,000	687,000	11,730,000
/STONE1&2	227,000	201,000	202,000	171,000	203,000	232,000	2,339,000
/STONE3&4	7,895,000	4,864,000	1,946,000	2,536,000	2,484,000	3,653,000	51,753,000
1,2,3,4	8,122,000	5,065,000	2,148,000	2,709,000	2,687,000	3,885,000	54,092,000
SULFUR)	818,000	629,000	677,000	0	0	0	2,772,000
STONE	8,940,000	5,694,000	2,825,000	2,709,000	2,687,000	3,885,000	56,864,000
BY#1	7,000	9,000	16,000	10,000	7,000	16,000	141,000
BY#2	2,035,000	641,000	2,066,000	1,501,000	1,203,000	1,757,000	13,507,000
SULFUR)	246,000	199,000	158,000	80,000	68,000	150,000	1,936,000
BY	2,288,000	849,000	2,240,000	1,591,000	1,278,000	1,923,000	15,584,000
HARE 7&8	2,797,000	2,027,000	1,245,000	1,049,000	428,000	1,186,000	18,392,000
MOND	0	0	0	0	0	0	0
MARK1&2	0	0	0	0	0	0	0
L OIL	16,198,000	9,751,000	7,342,000	6,038,000	4,856,000	7,681,000	102,570,000
STONE#1	2,312,000	2,056,000	2,031,000	2,200,000	2,087,000	1,921,000	25,249,000
STONE#2	2,751,000	1,845,000	2,518,000	2,407,000	2,475,000	1,870,000	19,792,000
STONE	5,063,000	3,901,000	4,549,000	4,607,000	4,562,000	3,791,000	45,041,000
Y#1	1,540,000	1,246,000	1,010,000	528,000	454,000	986,000	12,529,000
PECOAL	6,603,000	5,147,000	5,559,000	5,135,000	5,016,000	4,777,000	57,570,000
OR SCRUBBER							
TONE#1	0	0	18,000	286,000	268,000	247,000	2,072,000
TONE#2	0	0	23,000	310,000	318,000	238,000	1,587,000
GAS	0	0	41,000	596,000	586,000	485,000	3,659,000
OIL, TOTAL COAL & TOTAL GAS STEAM	22,801,000	14,898,000	12,942,000	11,769,000	10,458,000	12,943,000	163,799,000

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1.
Schedule E-3
Sheet 8 of 24

EC 30 1985

COST 2 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
IOUTH (PE SHARE)						
TN1 COAL	1,348,000	1,361,000	1,196,000	1,404,000	1,208,000	1,160,000
TN2 COAL	1,213,000	1,054,000	1,112,000	1,225,000	1,094,000	1,155,000
TONE C	2,561,000	2,415,000	2,308,000	2,629,000	2,302,000	2,315,000
T1&2 OIL	0	17,000	16,000	0	9,000	43,000
TONE	2,561,000	2,432,000	2,324,000	2,629,000	2,311,000	2,358,000
COAL	1,260,000	1,491,000	1,352,000	1,357,000	1,249,000	1,345,000
COAL	1,374,000	1,342,000	1,485,000	1,460,000	1,230,000	1,166,000
IAUGH C	2,634,000	2,833,000	2,837,000	2,817,000	2,479,000	2,511,000
2 OIL	7,000	7,000	7,000	14,000	14,000	28,000
IAUGH	2,641,000	2,840,000	2,844,000	2,831,000	2,493,000	2,539,000
IOUTH	5,202,000	5,272,000	5,169,000	5,460,000	4,804,000	4,897,000
AR (PE SHARE)						
UCLEAR	1,786,023	1,946,704	1,748,943	1,495,563	2,008,504	1,439,942
UCLEAR	1,739,358	2,065,905	1,566,089	1,426,140	1,006,295	2,019,255
INTREST	813,118	786,265	759,413	732,559	705,706	678,854
OMIC	4,338,499	4,798,874	4,074,445	3,654,262	3,720,505	4,138,051
OILER	28,778	28,778	27,900	29,698	28,740	29,698
ESEL	4,494	4,494	4,352	4,552	4,404	4,552
1	2,086,000	1,953,000	1,795,000	1,831,000	2,033,000	1,831,000
2	1,976,000	1,703,000	848,000	0	0	152,000
NTEREST	481,915	466,511	451,107	435,703	420,299	404,895
NTEREST	257,184	246,549	235,913	235,913	235,913	508,291
AUXBLR	0	0	0	0	0	0
DIESEL	200	200	200	200	200	200
UCLEAR	5,228,000	4,961,000	4,028,000	5,077,000	4,312,000	4,462,000
UCLEAR	0	0	0	0	0	0
C TOTAL	5,228,000	4,961,000	4,028,000	5,077,000	4,312,000	4,462,000
XBOILER	43,749	43,749	42,368	44,299	42,869	44,299
IESEL	7,122	7,122	6,897	7,211	6,979	7,211
AR	14,451,941	14,213,277	11,514,182	11,319,838	10,804,909	11,582,197
FOR JIM MILLER						
JC2	0	0	0	0	0	0
(PRECOMMERCIAL)	0	0	0	0	0	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 9 of 24

E.C.R.C. 1985

ECR FILING - 7/86 - 6/89

COST 2 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
MOUTH (PE SHARE)							
TN1 COAL	1,208,000	1,177,000	1,449,000	271,000	1,112,000	1,333,000	14,227,000
TN2 COAL	1,057,000	1,056,000	1,227,000	1,210,000	1,408,000	1,214,000	14,025,000
TONE C	2,265,000	2,233,000	2,676,000	1,481,000	2,520,000	2,547,000	28,252,000
T1&2 OIL	27,000	18,000	0	0	18,000	0	148,000
TONE	2,292,000	2,251,000	2,676,000	1,481,000	2,538,000	2,547,000	28,400,000
COAL	1,543,000	1,323,000	1,498,000	1,415,000	1,657,000	1,409,000	16,899,000
COAL	1,478,000	996,000	102,000	1,357,000	1,653,000	1,252,000	14,895,000
AUGH C	3,021,000	2,319,000	1,600,000	2,772,000	3,310,000	2,661,000	31,794,000
2 OIL	16,000	8,000	7,000	7,000	0	22,000	137,000
AUGH	3,037,000	2,327,000	1,607,000	2,779,000	3,310,000	2,683,000	31,931,000
OUTH	5,329,000	4,578,000	4,283,000	4,260,000	5,848,000	5,230,000	60,331,000
AR (PE SHARE)							
UCLEAR	1,915,803	98,880	0	0	1,798,577	1,999,138	16,238,077
UCLEAR	1,965,941	1,732,694	1,802,039	1,875,236	1,192,160	0	18,391,112
INTREST	664,921	650,987	969,237	937,582	919,860	902,138	9,520,640
OMIC	4,546,665	2,482,561	2,771,276	2,812,818	3,910,597	2,901,276	44,149,829
OILER	31,138	28,124	30,898	29,302	30,278	29,346	352,678
ESEL	4,920	4,444	4,902	4,698	4,856	4,702	55,370
1	1,946,000	1,906,000	2,095,000	2,081,000	2,223,000	2,129,000	23,909,000
2	1,805,000	1,481,000	1,468,000	1,947,000	1,487,000	2,142,000	15,009,000
NTEREST	389,491	374,087	358,683	343,279	327,876	312,472	4,766,318
NTEREST	491,860	475,430	458,999	442,568	426,138	409,707	4,424,465
AUXBLR	0	0	0	0	0	0	0
DIESEL	200	200	200	200	200	200	2,400
UCLEAR	4,428,000	3,842,000	4,403,000	0	0	0	40,741,000
UCLEAR	0	0	0	0	0	0	0
C TOTAL	4,428,000	3,842,000	4,403,000	0	0	0	40,741,000
XBOILER	47,888	43,254	47,713	45,736	47,260	45,770	538,954
IESEL	7,796	7,041	7,767	7,445	7,694	7,451	87,736
AR	13,698,958	10,644,141	11,646,438	7,714,046	8,464,899	7,981,924	134,036,750
FOR JIM MILLER							
JC2	0	0	0	0	0	0	0
(PRECOMMERCIAL)	0	0	0	0	0	0	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 10 of 24

EC 2 0 1985

ECR FILING - 7/86 - 6/89

L COST 3 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
SELS						
MBY D 1&2	1,400	0	0	0	5,800	2,500
AHARE D	1,400	1,400	0	1,100	2,500	0
THMARK D	0	0	0	0	0	0
UYLKILL D	0	0	1,400	400	0	0
STONE D	800	1,400	1,000	0	200	0
EMAUGH D	400	1,000	1,000	0	0	0
SEL	4,000	3,800	3,400	1,500	8,500	2,500
TURBINES						
THMARK CT	17,000	69,000	31,000	0	0	0
STONE CT	23,000	72,000	29,000	0	0	0
AHARE CT	23,000	67,000	32,000	0	0	0
UYLKILLCT	9,000	38,000	8,000	0	0	0
STER CT	17,000	50,000	23,000	0	0	0
S CT	29,000	63,000	29,000	0	0	0
R CT	20,000	68,000	26,000	0	0	0
MTG CT	0	0	0	0	0	0
GE CT	185,000	412,000	150,000	72,000	120,000	0
HE CT	0	0	0	0	0	0
HO CT	0	0	0	0	0	0
MOND CT	185,000	412,000	150,000	72,000	120,000	0
DON	798,000	1,321,000	632,000	402,000	365,000	260,000
M CT	3,000	5,000	3,000	0	0	0
TURBINES	1,124,000	2,165,000	963,000	474,000	485,000	260,000
L IC	1,128,000	2,168,800	966,400	475,500	493,500	262,500

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 11 of 24

DEC 30 1985

ECR FILING - 7/86 - 6/89

EL COST 3 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
ESELS							
OMBY D 1&2	0	4,000	800	0	0	0	14,500
LAWARE D	11,300	2,700	0	3,800	0	0	24,200
ITHWARK D	0	0	0	0	0	0	0
UYLKILL D	2,700	0	0	0	0	0	4,500
'STONE D	0	0	0	600	0	0	4,000
EHAUGH D	0	0	0	600	0	0	3,000
SEL	14,000	6,700	800	5,000	0	0	50,200
TURBINES							
THWARK CT	0	0	0	11,000	0	0	128,000
YSTONE CT	0	0	0	14,000	0	0	138,000
AWARE CT	0	0	0	29,000	0	0	151,000
UYLKILLCT	0	0	0	3,000	0	0	58,000
STER CT	0	0	0	17,000	0	0	107,000
LS CT	0	0	0	19,000	0	0	140,000
ER CT	0	0	0	19,000	0	0	133,000
HTG CT	0	0	0	0	0	0	0
GE CT	64,000	21,000	0	204,000	17,000	66,000	1,311,000
NE CT	0	0	0	0	0	0	0
NO CT	0	0	0	0	0	0	0
MOND CT	64,000	21,000	0	204,000	17,000	66,000	1,311,000
DON	723,000	780,000	169,000	537,000	131,000	226,000	6,344,000
H CT	0	0	0	2,000	0	0	13,000
TURBINES	787,000	801,000	169,000	855,000	148,000	292,000	8,523,000
L IC	801,000	807,700	169,800	860,000	148,000	292,000	8,573,200

DEC 30 1985

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 12 of 24

ECR FILING - 7/86 - 6/89

FUEL BURN 1 OF 6 (6 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
EDDYSTONE STATION						
ED1 #6OIL	2,100	2,100	2,300	2,300	2,100	2,300
ED1 SCR OIL	0	0	0	0	7,800	10,700
ED2 #6OIL	2,100	2,100	2,300	2,300	9,900	8,900
ED2 SCR OIL	0	0	0	0	0	4,100
ED1&2 #6OIL	4,200	4,200	4,600	4,600	12,000	11,200
ED12 SCR OIL	0	0	0	0	7,800	14,800
ED3 #6OIL	96,000	70,000	83,000	84,000	73,000	88,000
ED4 #6OIL	88,000	102,000	100,000	76,000	69,000	66,000
ED3&4 #6OIL	184,000	172,000	183,000	160,000	142,000	154,000
----STATION TOTALS---						
ED12 SCR OIL	0	0	0	0	7,800	14,800
ED1234 #6OIL	188,200	176,200	187,600	164,600	154,000	165,200
ED STA #6OIL	188,200	176,200	187,600	164,600	161,800	180,000
CROMBY STATION						
CR1 #6OIL	410	350	360	280	280	270
CR1 SCRUBOIL	5,000	6,000	5,900	7,200	6,400	7,400
CR2 #6OIL	1,310	1,310	1,270	1,310	64,980	85,330
----STATION TOTALS----						
SCRUBBEROIL	5,000	6,000	5,900	7,200	6,400	7,400
CR12 #6OIL	1,720	1,660	1,630	1,590	65,260	85,600
CR STA #6OIL	6,720	7,660	7,530	8,790	71,660	93,000
DEL7 #6OIL	33,000	32,000	29,000	32,000	28,000	33,000
DEL8 #6OIL	28,000	35,000	26,000	23,000	3,000	32,000
DEL STA 6OIL	61,000	67,000	55,000	55,000	31,000	65,000
RICH9 #6OIL	0	0	0	0	0	0
SOUTHWARK STATION						
SWK1 #6OIL	0	0	0	0	0	0
SWK2 #6OIL	0	0	0	0	0	0
SWK STA 6OIL	0	0	0	0	0	0
SCHUY1 #6OIL	41,000	33,000	40,000	8,000	35,000	36,000
TOTAL #6OIL FOR ALL STEAM UNITS:						
STEAM #6OIL	296,920	283,860	290,130	236,390	299,460	374,000

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 13 of 24

ECR FILING - 7/86 - 6/89

FUEL BURN 1 OF 6 (6 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
EDDYSTONE STATION							
ED1 #6OIL	2,400	2,000	2,300	2,100	2,300	2,300	26,600
ED1 SCR OIL	12,400	11,100	10,100	0	0	0	52,100
ED2 #6OIL	0	3,300	(100)	2,100	2,300	2,300	37,500
ED2 SCR OIL	14,800	9,800	12,500	0	0	0	41,200
ED1&2 #6OIL	2,400	5,300	2,200	4,200	4,600	4,600	64,100
ED12 SCR OIL	27,200	20,900	22,600	0	0	0	93,300
ED3 #6OIL	131,000	39,000	33,000	54,000	39,000	78,000	868,000
ED4 #6OIL	129,000	121,000	31,000	32,000	45,000	45,000	904,000
ED3&4 #6OIL	260,000	160,000	64,000	86,000	84,000	123,000	1,772,000
----STATION TOTALS---							
ED12 SCR OIL	27,200	20,900	22,600	0	0	0	93,300
ED1234 #6OIL	262,400	165,300	66,200	90,200	88,600	127,600	1,836,100
ED STA #6OIL	289,600	186,200	88,800	90,200	88,600	127,600	1,929,400
CROMBY STATION							
CR1 #6OIL	170	230	380	270	190	380	3,570
CR1 SCRUBOIL	8,500	6,900	5,500	2,800	2,400	5,300	69,300
CR2 #6OIL	70,120	22,040	71,390	53,100	42,520	61,990	476,670
----STATION TOTALS----							
SCRUBBEROIL	8,500	6,900	5,500	2,800	2,400	5,300	69,300
CR12 #6OIL	70,290	22,270	71,770	53,370	42,710	62,370	480,240
CR STA #6OIL	78,790	29,170	77,270	56,170	45,110	67,670	549,540
DEL7 #6OIL	56,000	31,000	20,000	17,000	5,000	21,000	337,000
DEL8 #6OIL	36,000	35,000	20,000	17,000	9,000	18,000	282,000
DEL STA 6OIL	92,000	66,000	40,000	34,000	14,000	39,000	619,000
RICH9 #6OIL	0	0	0	0	0	0	0
SOUTHWARK STATION							
SWK1 #6OIL	0	0	0	0	0	0	0
SWK2 #6OIL	0	0	0	0	0	0	0
SWK STA 6OIL	0	0	0	0	0	0	0
SCHUY1 #6OIL	71,000	39,000	34,000	23,000	16,000	23,000	399,000
TOTAL #6OIL FOR ALL STEAM UNITS:							
STEAM #6OIL	531,390	320,370	240,070	203,370	163,710	257,270	3,496,940

DEC 30 1985

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 14 of 24

ECR FILING - 7/86 - 6/89

FUEL BURN 2 OF 6 (6 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
PEACH BOTTOM AUX. BOILER (PE SHARE ONLY)						
PB2 #6OIL	537	537	520	537	520	537
PB3 #6OIL	537	537	520	537	520	537
PB STA 6OIL	1,074	1,074	1,040	1,074	1,040	1,074
NUCL #6OIL	1,074	1,074	1,040	1,074	1,040	1,074
TOTAL 6OIL FOR ALL ELECTRIC OUTPUT:						
ELECTRIC	297,994	284,934	291,170	237,464	300,500	375,074
STEAM HEAT (SCHUYLKILL TRANSFER, MILLON & EDISON).						
TRANSFER	26,700	38,500	34,900	42,100	70,100	148,500
MILLON	0	0	0	0	0	0
EDISON	8,545	2,568	872	892	1,983	4,028
TOTAL STEAM	35,245	41,068	35,772	42,992	72,083	152,528
PEACH BOTTOM AUX. BOILER (PS, AE, DPL SHARES)						
PB2AUX NONPE	727	727	704	727	704	727
PB3AUX NONPE	727	727	704	727	704	727
PB AUX NONPE	1,454	1,454	1,408	1,454	1,408	1,454
TOTAL BARRELS TO BE PURCHASED						
NO 6 OIL	334,693	327,456	328,350	281,910	373,991	529,056

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 15 of 24

DEC 30 1985

ECR FILING - 7/86 - 6/89

FUEL BURN 2 OF 6 (6 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
PEACH BOTTON AUX. BOILER (PE SHARE ONLY)							
PB2 #6OIL	537	485	537	520	537	520	6,324
PB3 #6OIL	537	485	537	520	537	520	6,324
PB STA 6OIL	1,074	970	1,074	1,040	1,074	1,040	12,648
NUCL #6OIL	1,074	970	1,074	1,040	1,074	1,040	12,648
TOTAL 6OIL FOR ALL ELECTRIC OUTPUT:							
ELECTRIC	532,464	321,340	241,144	204,410	164,784	258,310	3,509,588
STEAM HEAT (SCHUYLKILL TRANSFER, HILLON & EDISON).							
TRANSFER	194,800	185,500	170,800	120,800	55,700	43,900	1,132,300
HILLON	0	0	0	0	0	0	0
EDISON	8,082	17,273	8,306	2,734	994	731	57,008
TOTAL STEAM	202,882	202,773	179,106	123,534	56,694	44,631	1,189,308
PEACH BOTTOM AUX. BOILER (PS, AE, DPL SHARES)							
PB2AUX NONPE	727	657	727	704	727	704	8,562
PB3AUX NONPE	727	657	727	704	727	704	8,562
PB AUX NONPE	1,454	1,314	1,454	1,408	1,454	1,408	17,124
TOTAL BARRELS TO BE PURCHASED							
NO 6 OIL	736,800	525,427	421,704	329,352	222,932	304,349	4,716,020

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 16 of 24

DEC 30 1986

ECR FILING - 7/86 - 6/89

FUEL BURN 3 OF 6 (2 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
STEAM STATIONS						
ED1 #2OIL	700	700	1,300	1,300	700	1,300
ED2 #2OIL	1,100	700	700	700	700	1,100
ED3 #2OIL	800	600	700	700	600	800
ED4 #2OIL	700	800	800	600	600	500
ED STA #2OIL	3,300	2,800	3,500	3,300	2,600	3,700
CR1 #2OIL	140	120	120	100	100	90
CR2 #2OIL	0	0	0	0	90	130
CR STA #2OIL	140	120	120	100	190	220
DEL7 #2OIL	590	480	560	560	520	820
DEL8 #2OIL	430	490	420	570	170	740
DEL STA 2OIL	1,020	970	980	1,130	690	1,560
RICH9 #2OIL	0	0	0	0	0	0
SNK1 #2OIL	0	0	0	0	0	0
SNK2 #2OIL	0	0	0	0	0	0
SNK STA 2OIL	0	0	0	0	0	0
SCHUY1 #2OIL	150	110	150	50	110	150
PHILA AREA STEAM UNITS:						
PHL STM 2OIL	4,610	4,000	4,750	4,580	3,590	5,630
MINEMOUTH STATIONS						
KEYST1 #2OIL	0	0	300	0	0	800
KEYST2 #2OIL	0	500	300	0	300	500
KEY STA 2OIL	0	500	600	0	300	1,300
CON1 #2OIL	200	0	0	400	0	400
CON2 #2OIL	0	200	200	0	400	400
CON STA 2OIL	200	200	200	400	400	800
MINEMTH 2OIL	200	700	800	400	700	2,100
PHILA AREA & MINEMTH TOTAL:						
STEAM #2OIL	4,810	4,700	5,550	4,980	4,290	7,730

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 17 of 24

DEC 30 1985

ECR FILING - 7/86 - 6/89

FUEL BURN 3 OF 6 (2 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
STEAM STATIONS							
ED1 #2OIL	1,300	600	1,300	700	1,300	1,300	12,500
ED2 #2OIL	1,100	1,400	700	700	700	1,400	11,000
ED3 #2OIL	1,200	300	300	400	300	700	7,400
ED4 #2OIL	1,200	1,000	200	200	300	400	7,300
ED STA #2OIL	4,800	3,300	2,500	2,000	2,600	3,800	38,200
CR1 #2OIL	60	80	130	90	60	130	1,220
CR2 #2OIL	60	70	100	110	100	100	760
CR STA #2OIL	120	150	230	200	160	230	1,980
DEL7 #2OIL	560	480	640	420	130	430	6,190
DEL8 #2OIL	700	510	540	410	320	530	5,830
DEL STA 2OIL	1,260	990	1,180	830	450	960	12,020
RICH9 #2OIL	0	0	0	0	0	0	0
SNK1 #2OIL	0	0	0	0	0	0	0
SNK2 #2OIL	0	0	0	0	0	0	0
SNK STA 2OIL	0	0	0	0	0	0	0
SCHUY1 #2OIL	140	100	140	150	90	140	1,480
PHILA AREA STEAM UNITS:							
PHL STM 2OIL	6,320	4,540	4,050	3,180	3,300	5,130	53,680
MINEMOUTH STATIONS							
KEYST1 #2OIL	300	300	0	0	500	0	2,200
KEYST2 #2OIL	500	300	0	0	0	0	2,400
KEY STA 2OIL	800	600	0	0	500	0	4,600
CON1 #2OIL	200	0	0	0	0	200	1,400
CON2 #2OIL	200	200	200	200	0	400	2,400
CON STA 2OIL	400	200	200	200	0	600	3,800
MINEMTH 2OIL	1,200	800	200	200	500	600	8,400
PHILA AREA & MINEMTH TOTAL:							
STEAM #2OIL	7,520	5,340	4,250	3,380	3,800	5,730	62,080

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 18 of 24

DEC 30 1985

ECR FILING - 7/86 - 6/89

FUEL BURN 4 OF 6 (2 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
DIESEL FOR NUCLEAR UNITS						
PEACH BOTTOM (PE SHARE ONLY)						
PB2 #2OIL	67	67	64	67	64	67
PB3 #2OIL	67	67	64	67	64	67
PB STA 2OIL	134	134	128	134	128	134
SALEM1 #2OIL	3	3	3	3	3	3
SALEM2 #2OIL	3	3	3	3	3	3
SAL STA 2OIL	6	6	6	6	6	6
LIM1 AUX BLR	1,300	1,300	1,300	1,300	1,300	1,300
LIM2 AUX BLR	0	0	0	0	0	0
LIM STA AUX	1,300	1,300	1,300	1,300	1,300	1,300
LIM1 DIESEL	210	210	161	210	161	210
LIM2 DIESEL	0	0	0	0	0	0
LIM STA DSL	210	210	161	210	161	210
LIM STA 2OIL	1,510	1,510	1,461	1,510	1,461	1,510
TOTAL FOR ALL NUCLEAR UNITS (PE SHARE)						
NUCL #2OIL	1,650	1,650	1,595	1,650	1,595	1,650
PEACH BOTTOM DIESEL (PS, AE, &DPL SHARES)						
PB2DSL NONPE	91	91	86	91	86	91
PB3DSL NONPE	91	91	86	91	86	91
PB DSL NONPE	182	182	172	182	172	182
LIMERPC AUX	0	0	0	0	0	0
LIMERPC DSL	0	0	0	0	0	0
LIMER PRECOM	0	0	0	0	0	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 19 of 24

ECR FILING - 7/86 - 6/89

FUEL BURN 4 OF 6 (2 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
DIESEL FOR NUCLEAR UNITS							
PEACH BOTTOM (PE SHARE ONLY)							
PB2 #2OIL	67	60	67	64	67	64	785
PB3 #2OIL	67	60	67	64	67	64	785
PB STA 2OIL	134	120	134	128	134	128	1,570
SALEM1 #2OIL	3	3	3	3	3	3	36
SALEM2 #2OIL	3	3	3	3	3	3	36
SAL STA 2OIL	6	6	6	6	6	6	72
LIM1 AUX BLR	1,300	1,200	1,300	1,300	1,300	1,300	15,500
LIM2 AUX BLR	0	0	0	0	0	0	0
LIM STA AUX	1,300	1,200	1,300	1,300	1,300	1,300	15,500
LIM1 DIESEL	210	164	210	161	210	161	2,278
LIM2 DIESEL	0	0	0	0	0	0	0
LIM STA DSL	210	164	210	161	210	161	2,278
LIM STA 2OIL	1,510	1,364	1,510	1,461	1,510	1,461	17,778
TOTAL FOR ALL NUCLEAR UNITS (PE SHARE)							
NUCL #2OIL	1,650	1,490	1,650	1,595	1,650	1,595	19,420
PEACH BOTTOM DIESEL (PS, AE, &DPL SHARES)							
PB2DSL NONPE	91	82	91	86	91	86	1,063
PB3DSL NONPE	91	82	91	86	91	86	1,063
PB DSL NONPE	182	164	182	172	182	172	2,126
LIMERPC AUX	0	0	0	0	0	0	0
LIMERPC DSL	0	0	0	0	0	0	0
LIMER PRECOM	0	0	0	0	0	0	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 20 of 24

DEC 30 1985

ECR FILING - 7/86 - 6/89

FUEL BURN 5 OF 6 (2 OIL BBLS.)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
INTERNAL COMBUSTION						
RICH GE CT	5,700	12,700	4,600	2,200	3,600	0
RICH NE CT	0	0	0	0	0	0
RICH NO CT	0	0	0	0	0	0
RICHCT TOTAL	5,700	12,700	4,600	2,200	3,600	0
SOUTHWARK CT	520	2,070	920	0	0	0
EDDYSTONE CT	690	2,140	850	0	0	0
DELAWARE CT	670	2,000	950	0	0	0
SCHUYLKILLCT	270	1,140	230	0	0	0
CHESTER CT	520	1,500	690	0	0	0
FALLS CT	870	1,870	850	0	0	0
MOSER CT	600	2,000	770	0	0	0
PLY MTG CT	0	0	0	0	0	0
PE SUBTOTAL	9,840	25,420	9,860	2,200	3,600	0
CROYDON	25,000	41,000	19,000	12,000	11,000	8,000
PE CT TOTAL	34,840	66,420	28,860	14,200	14,600	8,000
PE DIESELS	80	40	40	40	240	70
PE TOTAL	34,920	66,460	28,900	14,240	14,840	8,070
MINEMOUTH D	40	70	60	0	10	0
SALEM#3	86	171	87	0	0	0
TOTAL IC	35,046	66,701	29,047	14,240	14,850	8,070
STEAM HEAT	8	6	4	4	13	21
TOTAL BARRELS TO BE PURCHASED (EXCLUDES MINEMOUTH & SALEM)						
NO 2 OIL	41,364	72,292	35,415	20,650	20,204	15,547
TOTAL NO 2 OIL FOR PE ELECTRIC SYSTEM (EXCLUDES STEAM HEAT & PB2&3(NONPE))						
TOTAL NO 2	41,506	73,051	36,192	20,870	20,735	17,450

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 21 of 24

DEC 30 1985

ECR FILING - 7/86 - 6/89

FUEL BURN 5 OF 6 (2 OIL BBLS.)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
INTERNAL COMBUSTION							
RICH GE CT	1,800	600	0	5,800	500	1,900	39,400
RICH NE CT	0	0	0	0	0	0	0
RICH NO CT	0	0	0	0	0	0	0
RICHCT TOTAL	1,800	600	0	5,800	500	1,900	39,400
SOUTHWARK CT	0	0	0	310	0	0	3,820
EDDYSTONE CT	0	0	0	390	0	0	4,070
DELAWARE CT	0	0	0	800	0	0	4,420
SCHUYLKILLCT	0	0	0	80	0	0	1,720
CHESTER CT	0	0	0	470	0	0	3,180
FALLS CT	0	0	0	510	0	0	4,100
MOSER CT	0	0	0	520	0	0	3,890
PLY MTG CT	0	0	0	0	0	0	0
PE SUBTOTAL	1,800	600	0	8,880	500	1,900	64,600
CROYDON	20,000	22,000	5,000	15,000	4,000	6,000	188,000
PE CT TOTAL	21,800	22,600	5,000	23,880	4,500	7,900	252,600
PE DIESELS	380	170	20	110	0	0	1,190
PE TOTAL	22,180	22,770	5,020	23,990	4,500	7,900	253,790
MINEMOUTH D	0	0	0	40	0	0	220
SALEM#3	0	0	0	69	0	0	413
TOTAL IC	22,180	22,770	5,020	24,099	4,500	7,900	254,423
STEAM HEAT	20	21	27	14	6	3	147
TOTAL BARRELS TO BE PURCHASED (EXCLUDES MINEMOUTH & SALEM)							
NO 2 OIL	30,346	28,979	10,923	28,945	9,632	14,794	329,091
TOTAL NO 2 OIL FOR PE ELECTRIC SYSTEM (EXCLUDES STEAM HEAT & PB2&3(NONPE))							
TOTAL NO 2	31,350	29,600	10,920	29,074	9,950	15,225	335,923

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 22 of 24

DEC 26 1985

ECR FILING - 7/86 - 6/89

FUEL BURN 6 OF 6 (TONS & MCF)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
TONS OF COAL						
PHILA AREA COAL						
ED1 COAL	38,000	43,000	42,000	47,000	44,000	39,000
ED2 COAL	42,000	51,000	11,000	0	0	15,000
ED STA COAL	80,000	94,000	53,000	47,000	44,000	54,000
CR1 COAL	20,000	24,000	23,000	28,000	25,000	29,000
PE COAL	100,000	118,000	76,000	75,000	69,000	83,000
MINEMOUTH COAL						
CON1 COAL	32,000	38,000	34,000	34,000	31,000	34,000
CON2 COAL	35,000	34,000	38,000	37,000	31,000	29,000
CON STA COAL	67,000	72,000	72,000	71,000	62,000	63,000
KEYST1 COAL	43,000	43,000	38,000	44,000	38,000	36,000
KEYST2 COAL	39,000	34,000	35,000	38,000	34,000	36,000
KEY STA COAL	82,000	77,000	73,000	82,000	72,000	72,000
MINEMTH COAL	149,000	149,000	145,000	153,000	134,000	135,000
TOTAL COAL	249,000	267,000	221,000	228,000	203,000	218,000
MCF OF GAS (EDDYSTONE SCRUBBER RELATED)						
ED1 SCRUBGAS	63,000	72,000	70,000	78,000	27,000	0
ED2 SCRUBGAS	70,000	85,000	18,000	0	0	0
TOTAL GAS	133,000	157,000	88,000	78,000	27,000	0

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 23 of 24

DEC 20 1985

ECR FILING - 7/86 - 6/89

FUEL BURN 6 OF 6 (TONS & MCF)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
TONS OF COAL							
PHILA AREA COAL							
ED1 COAL	45,000	40,000	40,000	43,000	40,000	37,000	498,000
ED2 COAL	54,000	36,000	49,000	47,000	48,000	36,000	389,000
ED STA COAL	99,000	76,000	89,000	90,000	88,000	73,000	887,000
CR1 COAL	33,000	27,000	22,000	11,000	10,000	21,000	273,000
PE COAL	132,000	103,000	111,000	101,000	98,000	94,000	1,160,000
MINEMOUTH COAL							
CON1 COAL	38,000	33,000	37,000	35,000	40,000	34,000	420,000
CON2 COAL	36,000	25,000	2,000	33,000	40,000	31,000	371,000
CON STA COAL	74,000	58,000	39,000	68,000	80,000	65,000	791,000
KEYST1 COAL	37,000	36,000	45,000	8,000	34,000	41,000	443,000
KEYST2 COAL	33,000	33,000	38,000	37,000	43,000	37,000	437,000
KEY STA COAL	70,000	69,000	83,000	45,000	77,000	78,000	880,000
MINEMTH COAL	144,000	127,000	122,000	113,000	157,000	143,000	1,671,000
TOTAL COAL	276,000	230,000	233,000	214,000	255,000	237,000	2,831,000
MCF OF GAS (EDDYSTONE SCRUBBER RELATED)							
ED1 SCRUBGAS	0	0	5,000	71,000	66,000	61,000	513,000
ED2 SCRUBGAS	0	0	6,000	77,000	79,000	59,000	394,000
TOTAL GAS	0	0	11,000	148,000	145,000	120,000	907,000

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-3
Sheet 24 of 24

DEC 30 1985

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
REPORT ENDED JAN'86

	TOTAL SYSTEM SALES KWH	CURRENT ENERGY COST MILLS/KWH	TOTAL ENERGY COST $	ALLOC. FACTOR	ENERGY COST PECO RETAIL CUSTOMER $	RETAIL CUSTOMER SALES KWH	ENERGY COST RECOVERED IN BASE RATES $	ENERGY COST OVER BASE $	ECR FACTOR MILLS/KWH	ECR REVENUE $	OTHER REVENUE $	TOTAL ECR REVENUE $	O/U RECOVERY $
	1	2=3/1X 1000	3 (C,D)	4	5=3X4	6	7=6XBASE	8=5-7	9(A)	10=9X6	11(B)	12=10+11	13=12-8
FEB'85	2520132788.	29.022	73138782.	0.9741	71244488.	2459350733.	69299585.	1944903.	-1.238635	-3046238.	-414940.	-3461178.	-5406081.
MAR'85	2274670800.	24.812	56439827.	0.9755	55057051.	2216448759.	62455093.	-7398042.	-1.238635	-2745371.	-770448.	-3515819.	3882223.
APR'85	2180772632.	23.188	50567045.	0.9758	49343323.	2127576959.	59950864.	-10607541.	-1.820470	-3873189.	-300059.	-4173248.	6434293.
MAY'85	2133269785.	24.166	51552357.	0.9770	50366653.	2080384413.	58621072.	-8254419.	-2.171623	-4517811.	-222280.	-4740091.	3514328.
JUN'85	2176308704.	25.667	55859617.	0.9775	54602776.	2124535844.	59865171.	-5262395.	-2.184085	-4640167.	505451.	-4134716.	1127679.
JUL'85	2406564458.	32.179	77440332.	0.9812	75984454.	2355394746.	66370313.	9614141.	-2.184085	-5144382.	499633.	-4644749.	-14258890.
AUG'85	2527057557.	28.968	73202854.	0.9807	71790039.	2474913183.	69738104.	2051935.	-2.184085	-5405421.	589708.	-4815713.	-6867648.
SEP'85	2494818450.	24.581	61325386.	0.9735	59700263.	2429767806.	68465997.	-8765734.	-2.184085	-5306819.	507674.	-4799145.	3966589.
OCT'85	2279767534.	27.990	63811405.	0.9816	62637275.	2237250322.	63041240.	-403965.	-2.184085	-4886345.	-280078.	-5166423.	-4762458.
NOV'85	2121277797.	19.724	41839834.	0.9791	40965381.	2073592014.	58429676.	-17464295.	-2.184085	-4528901.	-310982.	-4839883.	12624412.
DEC'85	2397824000.	31.167	74734110.	0.9768	73000279.	2339024000.	65909018.	7091261.	-2.184085	-5108627.	0.	-5108627.	-12199888.
JAN'86	2564421000.	25.191	64600513.	0.9770	63114701.	2502721000.	70521672.	-7406971.	-2.184085	-5466155.	0.	-5466155.	1940816.
YEARLY TOTAL TO DATE	28076885505.		744512062.		727806683.	27420959779	772667805.	-44861122.		-54669426.	-196321.	-54865747.	-10004625.

BASE = 28.178 MILLS/KWH

(A) AVERAGE ENERGY COST FACTOR FOR PERIOD EXCLUDING GRT AND CORRECTION FACTOR

(B) RATE HT TIME-OF-USE ADJUSTMENT INCLUDED IN ECR CALCULATION
PER COMMISSION ORDER ENTERED MAY 21, 1982 AT RATE
CASE NO. R-811626, PAGE 60.

(C) BEGINNING MAY 1984, FUEL COSTS AND SALES ASSOCIATED WITH NIGHT SERVICE HT RIDER-SUPPLEMENTAL ENERGY
WILL BE EXCLUDED FROM TOTAL FUEL COSTS AND SYSTEM SALES.

(D) BEGINNING JANUARY 25, 1985, SALEM 2 FUEL SAVINGS WILL BE ADDED TO THE TOTAL ENERGY COST.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-4
Sheet 1 of 5

DEC 30 1985

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
REPORT ENDED JAN'86

	O/U RECOVERY 13	INT. RATE 14	INT. FACTOR 15	INTEREST 16=13X14X15/100
FEB'85	-5406081.	13.75	24./12	-1486672.
MAR'85	3882223.	13.75	23./12	1023128.
APR'85	6434293.	13.75	22./12	1621978.
MAY'85	3514328.	14.25	21./12	876385.
JUN'85	1127679.	14.00	20./12	263125.
JUL'85	-14258890.	13.50	19./12	-3047838.
AUG'85	-6867648.	12.75	18./12	-1313438.
SEP'85	3966589.	13.00	17./12	730513.
OCT'85	-4762458.	13.00	16./12	-825493.
NOV'85	12624412.	13.25	15./12	1327430.
DEC'85	-12199888.	12.25	14./12	-1743567.
JAN'86	1940816.	12.25	13./12	257562.
YEARLY TOTAL TO DATE	-10004625.			-2316887.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-4
Sheet 2 of 5

DEC 30 1985

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
ESTIMATED REPORT ENDED APR'86

	TOTAL SYSTEM SALES KWH 1	CURRENT ENERGY COST MILLS/KWH 2=3/1X 1000	TOTAL ENERGY COST $ 3 (C)	ALLOC. FACTOR 4	ENERGY COST PECO RETAIL CUSTOMER $ 5=3X4	RETAIL CUSTOMER SALES KWH 6	ENERGY COST RECOVERED IN BASE RATES $ 7=6XBASE	ENERGY COST OVER BASE $ 8=5-7	ECR FACTOR MILLS/KWH 9(A)	ECR REVENUE $ 10=9X6	OTHER REVENUE $ 11(B)	TOTAL ECR REVENUE $ 12=10+11	O/U RECOVERY $ 13=12-8
FEB'86	2444721000.	22.241	54373227.	0.9785	53204203.	2393121000.	67433364.	-14229161.	-2.184085	-5226780.	0.	-5226780.	9002381.
MAR'86	2319721000.	27.615	64059068.	0.9786	62688204.	2267121000.	63882936.	-1194732.	-2.184085	-4951585.	0.	-4951585.	-3756853.
APR'86	2180772632.	20.580	44888280.	0.9791	43950115.	2203618000.	62009014.	-18058899.	-5.464646	-12025598.	0.	-12025598.	6033302.
YEARLY TOTAL TO DATE	6945214632.		163320575.		159842522.	6860860000	193325314.	-33482792.		-22203963.	0.	-22203963.	11278830.

BASE = 28.178 MILLS/KWH

(A) AVERAGE ENERGY COST FACTOR FOR PERIOD EXCLUDING GRT AND CORRECTION FACTOR

(B) RATE HT TIME-OF-USE ADJUSTMENT INCLUDED IN ECR CALCULATION
PER COMMISSION ORDER ENTERED MAY 21, 1982 AT RATE
CASE NO. R-811626, PAGE 60.

(C) BEGINNING MAY 1984, FUEL COSTS AND SALES ASSOCIATED WITH NIGHT SERVICE HT RIDER-SUPPLEMENTAL ENERGY
WILL BE EXCLUDED FROM TOTAL FUEL COSTS AND SYSTEM SALES.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-4
Sheet 3 of 5

DEC 30 1985

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
ESTIMATED REPORT ENDED APR'86

		O/U RECOVERY 13	INT. RATE 14	INT. FACTOR 15	INTEREST 16=13X14X15/100
INTEREST FOR 12 MONTHS ENDED JAN'86					-2316887
	FEB'86	9002381.	12.25	12./12	1102792.
	MAR'86	-3756853.	12.25	11./12	-421863.
	APR'86	6033302.	12.25	10./12	615900.
YEARLY TOTAL TO DATE		11278830.			-1020058.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-4
Sheet 4 of 5

DEC 30 1985

Philadelphia Electric Company
Reconciliation of Correction Factor
February 1986 Through April 1986
Estimated

Beginning Balance 1-31-86			($83,174,571)
Amount Recovered by "E" Factor:			
	kWH Sales to Pa. Jurisdictional Customers	"E" Factor Mills/kWh (Excl. GRT)	
Feb '86 & Mar '86	4,660,242,000	6.069025	28,283,125
April 1986	2,200,618,000	2.954510	6,501,748
Overcollection at 4-30-86			11,278,830
Applicable Interest due customer			0
Ending Balance 4-30-86 (To be recouped via "E" factor effective 6-27-86)			($37,110,868)

December 30, 1985
0034/79H

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
ESTIMATED REPORT ENDED JUN'87

	TOTAL SYSTEM SALES KWH 1	CURRENT ENERGY COST MILLS/KWH 2=3/1X 1000	TOTAL ENERGY COST $ 3 (C)	ALLOC. FACTOR 4	ENERGY COST PECO RETAIL CUSTOMER $ 5=3X4	RETAIL CUSTOMER SALES KWH 6	ENERGY COST RECOVERED IN BASE RATES $ 7=6XBASE	ENERGY COST OVER BASE $ 8=5-7	ECR FACTOR MILLS/KWH 9(A)	ECR REVENUE $ 10=9X6	OTHER REVENUE $ 11(B)	TOTAL ECR REVENUE $ 12=10+11	O/U RECOVERY $ 13=12-8
JUL'86	2244718000.	17.677	39678920.	0.9807	38913117.	2198414000.	45777575.	-6864458.	-4.256482	-9357510.	0.	-9357510.	-2493052.
AUG'86	2109515000.	18.948	39970948.	0.9813	39223491.	2065014000.	42999787.	-3776296.	-4.256482	-8789695.	0.	-8789695.	-5013399.
SEP'86	2286617000.	17.279	39510345.	0.9813	38771502.	2241014000.	46664635.	-7893133.	-4.256482	-9538836.	0.	-9538836.	-1645703.
OCT'86	2566221000.	14.351	36827359.	0.9784	36031888.	2512014000.	52307668.	-16275780.	-4.256482	-10692342.	0.	-10692342.	5583438.
NOV'86	2605616000.	14.087	36704687.	0.9803	35981605.	2552814000.	53157246.	-17175641.	-4.256482	-10866007.	0.	-10866007.	6309634.
DEC'86	2543419000.	16.639	42318853.	0.9763	41315896.	2498814000.	52032804.	-10716908.	-4.256482	-10636157.	0.	-10636157.	80751.
JAN'87	2246617000.	15.698	35267966.	0.9767	34446222.	2196814000.	45744258.	-11298036.	-4.256482	-9350699.	0.	-9350699.	1947337.
FEB'87	2144520000.	18.748	40204617.	0.9781	39324136.	2098714000.	43701522.	-4377386.	-4.256482	-8933138.	0.	-8933138.	-4555752.
MAR'87	2449624000.	14.223	34841599.	0.9786	34095989.	2389114000.	49748521.	-15652532.	-4.256482	-10169221.	0.	-10169221.	5483311.
APR'87	2647321000.	14.915	39485897.	0.9792	38664590.	2584214000.	53811088.	-15146498.	-4.256482	-10999660.	0.	-10999660.	4146838.
MAY'87	2551621000.	15.188	38754305.	0.9807	38006347.	2498614000.	52028639.	-14022292.	-4.256482	-10635306.	0.	-10635306.	3386986.
JUN'87	2369221000.	22.358	52970887.	0.9816	51996223.	2316114000.	48228442.	3767781.	-4.256482	-9858498.	0.	-9858498.	-13626279.
YEARLY TOTAL TO DATE	28765030000.		476536383.		466771006.	28151668000	586202185.	-119431179.		-119827069.	0.	-119827069.	-395890.

BASE = 20.823 MILLS/KWH

(A) AVERAGE ENERGY COST FACTOR FOR PERIOD EXCLUDING GRT AND CORRECTION FACTOR

(B) RATE HT TIME-OF-USE ADJUSTMENT INCLUDED IN ECR CALCULATION
PER COMMISSION ORDER ENTERED MAY 21, 1982 AT RATE
CASE NO. R-811626, PAGE 60.

(C) BEGINNING MAY 1984, FUEL COSTS AND SALES ASSOCIATED WITH NIGHT SERVICE HT RIDER-SUPPLEMENTAL ENERGY
WILL BE EXCLUDED FROM TOTAL FUEL COSTS AND SYSTEM SALES.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 1
Schedule E-5
Sheet 1 of 2

DEC 30 1985

PHILADELPHIA ELECTRIC COMPANY-ELECTRIC OPERATIONS
ENERGY COST RATE RECONCILIATION
ESTIMATED REPORT ENDED JUN'87

	O/U RECOVERY 13	INT. RATE 14	INT. FACTOR 15	INTEREST 16=13X14X15/100
JUL'86	-2493052.	12.25	20./12	-508998.
AUG'86	-5013399.	12.25	19./12	-972391.
SEP'86	-1645703.	12.25	18./12	-302398.
OCT'86	5583438.	12.25	17./12	968959.
NOV'86	6309634.	12.25	16./12	1030574.
DEC'86	80751.	12.25	15./12	12365.
JAN'87	1947337.	12.25	14./12	278307.
FEB'87	-4555752.	12.25	13./12	-604586.
MAR'87	5483311.	12.25	12./12	671706.
APR'87	4146838.	12.25	11./12	465655.
MAY'87	3386986.	12.25	10./12	345755.
JUN'87	-13626279.	12.25	9./12	-1251914.
YEARLY TOTAL TO DATE	-395890.			133034.

REFERENCE:
ENERGY COST RATE FACTOR
STATEMENT NO. 2
Schedule E-5
Sheet 2 of 2

DEC 30 1986

Philadelphia Electric Company
STATEMENT OF REASONS

I. The projected ECRF of (3.076) m/kWh is a decrease of 0.448 m/kWh in comparison to the current ECR of (2.628) m/kWh. The reasons for this decrease are as follows:

1. A reduction in the cost of energy of 7.355 m/kWh as a result of the fuel savings anticipated when Limerick Unit #1 begins commercial operation.

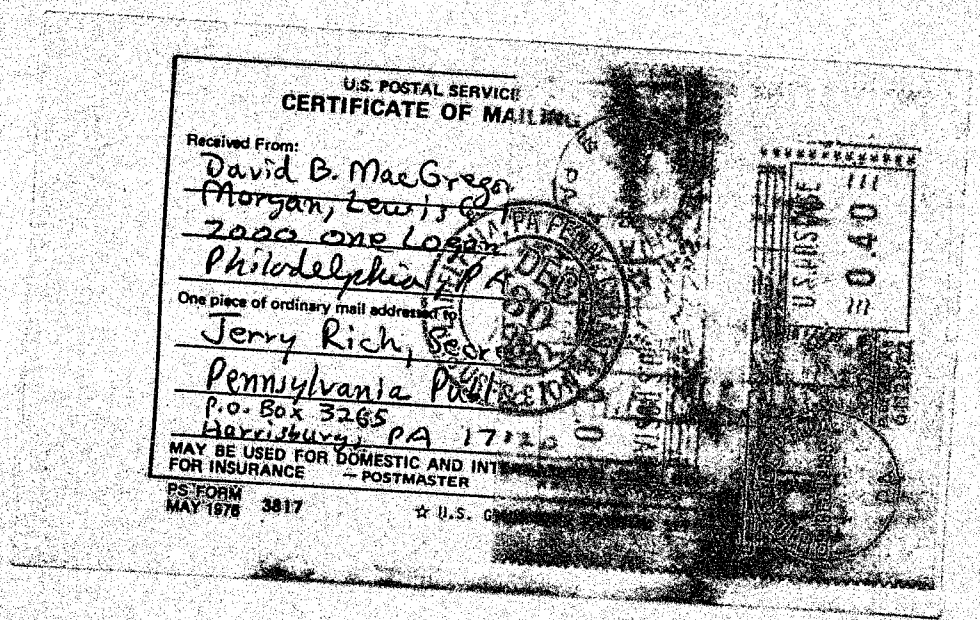
2. An undercollection of $37,110,868 applicable to the current ECRF which will be recovered by the correction factor of the proposed rate. This undercollection resulted in a 55.4% decrease to the "E" factor.

December 30, 1985
0034/79H

Residential Bill Analysis

The monthly cost of energy to the average Residential customer (500 kWh) will decrease 0.4% or $0.23 from $58.30 to $58.07.

December 30, 1985
0034/79H



U.S. POSTAL SERVICE
CERTIFICATE OF MAIL

Received From:
David B. MacGregor
Morgan, Lewis &
2000 one Logan
Philadelphia PA

One piece of ordinary mail addressed to:
Jerry Rich, Secretary
Pennsylvania Public
P.O. Box 3265
Harrisburg, PA 17

MAY BE USED FOR DOMESTIC AND INT
FOR INSURANCE — POSTMASTER

PS FORM
MAY 1976 3817

☆ U.S. G

MORGAN, LEWIS & BOCKIUS
COUNSELORS AT LAW
ONE LOGAN SQUARE
PHILADELPHIA, PENNSYLVANIA 19103
TELEPHONE: (215) 963-5000
CABLE ADDRESS: MORLEBOCK
TELEX: 83-1315

WASHINGTON
NEW YORK
LOS ANGELES

MIAMI
HARRISBURG
LONDON

DAVID B. MACGREGOR
DIAL DIRECT (215) 963-5448

DOCUMENT

December 30, 1985

RECEIVED
DEC 30 1985
SECRETARY'S OFFICE
Public Utility Commission

Jerry Rich, Secretary
Pennsylvania Public Utility Commission
P. O. Box 3265
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
Philadelphia Electric Company, Docket
No. R-850152

Dear Secretary Rich:

Enclosed for filing with the Commission are three copies of the following additional direct testimony and exhibits of Philadelphia Electric Company in the above-captioned proceeding: (1) Further Supplemental Direct Testimony of Thomas P. Hill, Jr. (Statement 18B), (2) Supplemental Direct Testimony of John J. Carroll (Statement 22A) and Exhibit JJC-1, (3) Supplemental Direct Testimony of Joseph F. Brennan (Statement 28A), and (4) Direct Testimony of Joseph W. Gallagher (Statement 30). These documents constitute the Company's response to the Commission's October 30, 1985 Order in its ECR No. 8 Investigation, Docket M-840375 et al., which directed the Company to file a revised Energy Cost Rate and certain supporting data in the Limerick 1 base rate proceeding.

These documents are being filed pursuant to 52 Pa. Code §1.11 by use of a U.S. Postal Service Form 3817 certificate of mailing. I hereby certify that I have today served copies of these documents on the Administrative Law Judge and all active parties to this proceeding.

Sincerely,

David B. MacGregor

Counsel for Philadelphia
Electric Company

/paa
Encl.
cc: Honorable Joseph P. Matuschak
All active parties

PECO Statement No. 22A

RECEIVED

DEC 30 1985

SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

SUPPLEMENTAL DIRECT TESTIMONY OF JOHN J. CARROLL

DATA REQUIREMENTS OF ECR NO. 8 ORDER, APPENDIX B EXPLANATION OF REVISED ECR PROJECTION ENERGY COST SCENARIO ANALYSES

DOCKETED

JAN 2 - 1986

DOCUMENT

December 1985

SUPPLEMENTAL DIRECT TESTIMONY OF JOHN J. CARROLL

Q. Are you the same John J. Carroll who previously presented direct testimony in this proceeding?

A. Yes. My direct testimony was previously admitted into evidence as PECO Statement No. 22. A full statement of my qualifications is set forth in that statement.

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my testimony is to provide a portion of the Company's response to the Commission's October 30, 1985 Order at Docket No. M-840375 et al, relating to the proposed modification to the Company's Energy Cost Rate ("ECR"). Specifically, my testimony will (1) provide the data and information requested in Appendix B of the Commission's Order, with the exception of Item (4)(i) which is contained in the testimony of Mr. J. W. Gallagher, Statement No. 30, (2) explain and support the Company's estimate of total fuel and interchange expenses for the period July 1, 1986 - June 30, 1987 to be used in the revised ECR; and (3) explain the basis for and results of sensitivity analyses made to examine the impact of unanticipated conditions of cost and energy

availability on PECO's future total fuel and interchange expense.

Q. Mr. Carroll, is the Company supplying the information requested in the Commission's October 30 Order?

A. Yes, the information and data requirements set forth in Appendix B of the Commission's October 30 Order are provided in Exhibit JJC-1, with the exception of Item (4)(i) "Generating Unit Performance Improvements", which will be addressed in the testimony of Mr. J. W. Gallagher, Statement No. 30.

Q. Please explain the information and data contained in Exhibit JJC-1.

A. Appendix B to the Commission's October 30 Order requests information and data relating to:

1) Energy Supply Mix and Energy Price Projections and the methodology used by the Company to arrive at these projections.

2) Actual Unit Data Report for PECO's generating units for five historical years and the first year new rates will be in effect.

3) Comparison of historical data to that used or developed for the first year new rates will be in effect.

4) Generating Unit Performance Improvements.

5) Purchased and Interchange Power statistics for the historical period, as well as that developed for the first year new rates will be in effect.

The above data is provided in the section of Exhibit JJC-1 which corresponds to the numbers and subscripts of Appendix B.

Q. Please explain the data provided in response to Items (1) and (1)(i) of Appendix B.

A. Exhibit JJC-1, Items (1) and (1)(i) provide a tabulation of results from the Production Cost model computer run which forms the calculational base for the Company's 1986-87 ECR claim for total fuel and interchange expense. The sheets showing the information requested are as follows:

Pages 1 and 2 of the response list the expected monthly generation and fuel dollars for the different classes of PECO generation by months and source (i.e., coal, nuclear, oil, hydro). These pages also show the quantity and cost of

Interchange Transactions by months from the various sources (PJM, Co-Generation from Steam Heat, Borderline and Two-Party).

Pages 3 through 8 show the generation by individual generating units for each month and pages 9-10 provide a summary by classes.

Pages 11 through 18 list the fuel cost by month for the various generating sources by fuel type and requirement; pages 19-20 summarize fuel costs by types of fuel.

Pages 21 through 22 list the Interchange Transactions by source, the Hydro generation and pumping requirements by months and the Monthly Sales and Company Use requirements.

Q. Mr. Carroll, please describe the information provided by the Company in response to Appendix B, Item (1)(ii).

A. Exhibit JJC-1, Item (1)(ii)(a) provides the requested narrative description of the Company's Production Cost Model. Item (1)(ii)(b) provides the requested Production Cost Model input and output data. Item (1)(ii)(c) describes significant changes to the ProdCost model over the last five years.

Q. Mr. Carroll, in Appendix B, Item 2, "Actual Unit Data Report", the Commission requests certain specific generating unit data. Is this data supplied in Exhibit JJC-1?

A. Most items of specific data requested in Item 2 of Appendix B have been supplied. However, where it was impossible to supply the specific data requested, PECO met with the Commission Staff and proposed the provision of alternative data acceptable to the Staff as maintained by the Company and in a format that is developed by PECO's ProdCost program. I would like to emphasize that all of the data requested in Appendix B is being supplied by the Company, in either the exact form or a comparable form, to that requested.

Q. Mr. Carroll, Appendix B, Item 3 asks the Company to supply a "Comparison of Unit Performance Data Report". Would you explain PECO's response to that data request?

A. Yes, Appendix B, Item 3 requests a comparison of various generating unit operating characteristics for the first year the new ECR is in effect with historic results for the preceding five-year period. This information is provided in Exhibit JJC-1, Item (3)(i). In addition, since any twelve-month period can experience fluctuations in generation mix and fuel cost due to outage cycles, especially at the nuclear plants, the Company has included in its response a three-year projection of the requested performance statistics for PECO's nuclear and fossil fired steam plants.

In reviewing Exhibit JJC-1, Item (3)(i), it should be noted that while individual units may be either high or low in their contribution to the generation mix in any single twelve month period as compared to long or intermediate term historic averages, the units of a collective class of generation will generally average out close to such historic averages over a 36-month period. Therefore, in examining the "Comparison of Unit Data Report" supplied in Appendix B, Item (3)(i), it is necessary to not only examine how a particular unit in a particular year compared to its history, but also how a class of generation over time compares to historic levels.

For example, the nature and extent of planned outages at coal units depend upon the scope of maintenance and other work scheduled for a particular outage, and the length of these outages will obviously have a significant impact on the equivalent availability factors for these units in any twelve-month period. Similarly, the Company's nuclear units are on 18-month refueling cycles. Thus, in any given 12-month period a particular unit may have a full refueling outage or no refueling outage at all. The timing of these outages obviously will affect the capacity factor of a particular unit in a particular 12-month period causing it to be above or below a long-term historic average.

Q. Mr. Carroll, please briefly explain the results of the comparison presented in Exhibit JJC-1, Data Request (3)(i).

A. The following summarizes this comparison:

Nuclear Units - The Equivalent Availability Factors and Net Capacity Factors during the first year new rates are in effect are projected to be equal or better for all units with a historical record, i.e., all units except Limerick 1. With respect to Limerick 1, the projected three-year Net Capacity Factor of 61.6% is in line with historic results for other PECO nuclear plants, and is reasonable given that it includes the period in which Limerick 1 is considered an immature unit for purposes of predicting a Forced Outage Rate. It is an industry accepted practice, borne out by years of statistics, that when a new plant is first placed in service the Forced Outage Rate will be higher than the level expected during its mature lifetime. This higher initial rate then decreases over a few years to the average expected over the lifetime. For this reason, we have used a higher Forced Outage Rate for Limerick No. 1 unit during its period being projected than is expected during the mature lifetime. In addition, a major portion of the first end-of-cycle outage for this unit falls within the first year the new ECR is in effect (July 1, 1986 through June 30, 1987). Given these facts, a predicted first-year Net Capacity Factor of 55.8% is reasonable.

Coal Fired Units - The Equivalent Availability Factors for all units, with the exception of Conemaugh No. 2, are better than their history, and this unit shows only a slight decrease in the first year. For the three prospective years, the class is projected to show improvements, primarily due to greater expectations from Eddystone No. 1 and No. 2 units, and small improvement at the other coal fired plants.

Oil Fired Steam Units - The equivalent availability factors for these units are expected, with the exception of Cromby No. 2, to remain high and possibly show some improvement. However, the capacity factors are expected to decrease as a result of increased base load generation. Cromby 2 is predicted to be low in the future test year due to a projected shutdown to permit full operation of the Limerick 1. The three year projection shows Cromby 2 returning to its normally expected level of equivalent availability.

Q. Mr. Carroll, what conclusions can be drawn from the comparison included in Data Request (3)(i) of Exhibit JJC-1?

A. The comparison shown in Data Request (3)(i) of Exhibit JJC-1 demonstrates that the Company has used a reasonable level of expected performance from its nuclear and coal fired base

load plants, as well as a reasonable level of expected availability at the oil fired steam units in projecting the total fuel and interchange expenses during the first year new rates will be in effect.

Q. Mr. Carroll, please describe the Company's response to Appendix B, Item 5.

A. Exhibit JJC-1 provides the requested data on purchased and interchange power for the five-year period 6/30/80 - 6/30/85 and for the first year new rates will be in effect.

Q. Mr. Carroll, the Commission's Order, at page 163, requests that the ALJ consider a comparison of PECO's projected unit performance to the historical performance of comparable units by other utilities, as an additional means of evaluating the reasonableness of the Company's projected total fuel and interchange expense included in its revised ECR filing. Has PECO provided historical statistics for comparable units operated by other utilities?

A. Due to the short amount of time between issuance of the Commission's Order and the date required for this filing, as well as the time demands of other important proceedings before the Commission, PECO has not been able to obtain and present meaningful historical data for comparable units operated by other utilities. However, this data collection

process has been started and it will be forwarded to the Commission and all parties in this case as soon as it is available.

With respect to the meaningfulness of comparing the projections of future operation of PECO's units to the historic statistics of comparable units operated by other utilities, PECO does not believe there are true comparable units, or at least a sufficient sample of true comparable units, to many if not all of its units, because of the unique operating conditions of size, operating temperature and pressure, fuel type and characteristics, climatic conditions, plant design considerations and environmental and regulatory restrictions. PECO strongly believes that its plants should be compared to their own history, and that future projections should be expected to maintain or show improvement on this history where appropriate. PECO also believes that unique explainable situations that prevent a unit from achieving this goal should be accepted. Thus, PECO believes that comparisons to other unit operating statistics as a measure of the reasonableness of claimed PECO unit operating performance is often of limited value.

However, notwithstanding these comments, PECO is collecting data on similar units for its nuclear and coal plants. With

respect to its nuclear units, PECO has tabulated and presented in Schedule 1 to this testimony historical data for comparable units from the NRC "Grey Book". Since this data is collected according to NRC definitions, it cannot be compared to the data submitted in Exhibit JJC-1. This is because the Forced Outage Rate, Forced Outage Hours and Availability Factor calculated for the NRC do not recognize partial outages of the units. The Company is in the process of adjusting the data to a consistent and comparable basis.

With respect to coal-fired units, PECO believes that because its Philadelphia Area Coal units operate with a magnesium oxide S02 removal system, the only plants that are presently using this method of S02 removal, that these plants do not have similar units that represent the total plant, anywhere in the United States.

PECO also believes that because of the unique design and operating conditions of Eddystone No. 1 units, there is no comparable unit operated by another utility. Eddystone No. 1 unit is the only supercritical unit with an operating design pressure of 5,000 psig and an operating design superheater temperature of 1200 degrees Fahrenheit. Similarly, because of the vintage and generation of the control system and cycle design of Eddystone No. 2 unit, only one other plant in the

United States could be considered as a comparable unit operated by another utility. PECO is presently collecting this historical data.

With respect to Cromby No. 1 and the minemouth plants at Keystone and Conemaugh Stations, PECO is in the process of collecting data on similar units.

Q. Mr. Carroll, turning to the second part of your testimony, please summarize the total fuel and interchange expense projections used in the calculation of the Company's revised ECR.

A. PECO is projecting that the total fuel and interchange expenses for the period from July 1, 1986 to June 30, 1987 will be $476,536,383 to supply a total sales projection of 28,700,515 mwh. This amounts to an average fuel cost for the period of 16.604 mills per kwh. These values of expense and sales, as well as all of the other information used in the Production Cost computer run, have been supplied as part of Exhibit JJC-1, Item 1.

Q. Please explain how the Company projected the above-referenced total fuel and interchange expenses used in developing its revised Energy Cost Rate Filing?

A. The Electric Production Department (EP Dept.) is requested to provide the Rate Division with its latest projection of total fuel and interchange expenses that will be incurred during the twelve month period that covers the filing year. The EP Dept. reviews the data requirements necessary to perform a ProdCost computer run for that twelve month period. When the EP Dept. is satisfied that the data represents the most reliable prediction of the expected conditions, it performs the computer analysis necessary to develop the total fuel and interchange expenses using the ProdCost program.

Q. What are the data requirements for use with the ProdCost program?

A. The ProdCost program requires data for the entire Pennsylvania-New Jersey-Maryland Interconnection (PJM) that will permit the program to simulate the economic dispatching philosophy of PJM for the entire period under study. This includes the following items for all PJM Companies:

- Unit Performance
- Projected Maintenance Schedules
- Forced Outage Rates
- Anticipated Hydro Output for Run-of-River and Storage Plants
- Capacity Additions and Retirements
- Energy Requirements

- Fuel Costs and Projected Escalation Rates for the Various Types of Fuel

- Two Party Purchase Agreements

Q. Would you please explain the "economic dispatching philosophy of the PJM".

A. The members of PJM operate as a single cost area with free flowing interconnection ties. This means that PJM schedules all available equipment of all member companies in such a manner as to meet the collective customer load of all companies at the lowest cost, regardless of ownership of the generating units that must be operated to meet that load. Because there are free flowing interconnection ties, all transmission of the combined member companies can be used to transport the energy from one member's generating source to another member's customer load without penalty, as long as the transmission system is operated within its reliability constraints.

Operating under this philosophy insures that the collective load will be satisfied at the minimum fuel cost. The contract among PJM members contains very rigid accounting rules to determine how the companies that generate power to meet customer load of other members are to be reimbursed for the expenses they incur. These rules are used to determine the costs incurred and the amount to be paid for interchange deliveries.

Q. Would you please explain how PECO collects the data mentioned above for both the PECO units and all the units of the other members of PJM.

A. Within the PJM organization, a ProdCost Task Force (PCTF), composed of representatives of all the member companies and reporting to the PJM Operating Committee, is charged with obtaining and keeping up to date the necessary information required from their respective companies in order to perform production cost analyses for PJM.

The Task Force is charged with providing a complete review of their input data every three months, and updates are supplied to all companies when appropriate. PECO's representative on the PCTF is responsible for updating the PJM data deck and, therefore, receives that data from the other companies in advance of the completion of the official update. Because PECO's representative shares this PJM responsibility with the responsibility assigned to him as a member of Philadelphia Electric Company's Electric Production Department to maintain PECO's updated ProdCost data deck, he is in frequent communication with his counterparts on the PCTF and obtains, on an expedited on-going basis any changes in other member companies' data.

PECO-specific data are assembled either by direct communication within the EP Dept. or through correspondence from other departments on a formal basis. Whenever the other departments review and change their forecasts that affect the projections of fuel and interchange, the EP Dept. is notified of these changes. Within the EP Dept., the reviews necessary to maintain updated data are performed on a rigid schedule. For instance, every month the maintenance outage schedule for the next twelve months is reviewed and changes made to reflect the present and expected conditions. This revised schedule is then submitted to the group responsible to the EP Dept. Management for monthly updates of the fuel and interchange expense projections.

Q. Mr. Carroll, how does PECO verify that the data used in its ProdCost program are correct?

A. The group responsible for the ProdCost program within the EP Dept. prepares a PJM Total Fuel and Interchange Projection, using the raw data as submitted. Then the results of this projection are compared with the historical values of generation by class. This comparison is made because often the raw data reflect historic averages which may or may not include unusually long forced outages on a particular unit, such as, for example, the extended forced outage of Eddystone 1, for replacement of main steam piping. It is often

appropriate, in projecting future fuel and interchange expense, to make adjustments to the historic data for a unit to eliminate the unusual effects of such an outage.

As the next step in the process, PECO makes appropriate adjustments to reflect a reasonable output/availability for the various classes of generation, in conformity with the historical levels, after consideration of capacity additions, retirements and load requirements. This procedure provides a verification of the input data with respect to availability. Inputs with respect to heat rates, incremental maintenance, incremental fuel and the like are verified by manual calculations and, finally, by an examination of the loading order of the PJM units as they relate to one another. If a unit changes its order of loading by a significant amount, then the input is reexamined and verified to insure that the change is justified. PECO can then use the data submitted with a high degree of confidence that the results of the ProdCost run will reflect expected conditions on the PJM interconnection.

Q. Previously, you indicated that a monthly update of PECO's maintenance schedule is prepared. Would you please explain the process used by the Company to prepare the projected maintenance schedule.

A. The starting point for preparing a projected maintenance schedule is the overall preventive maintenance schedule for the boilers, turbines and reactors operated by the Company. This overall schedule incorporates the timing of major turbine inspections, major boiler inspections, refueling and end-of-cycle outages for reactors, and minor inspections of boilers and turbines in the years when no major inspections are scheduled. It also recognizes modifications and capital improvements that will be performed in conjunction with unit outages. Based on this overall schedule, the generating stations supply a description of the work projects that will be performed during the outages assigned to them for the future period. In addition, the Engineering and Research Department requests the time requirements necessary to perform their modifications and capital improvements.

The stations' work projects are then converted into outage days in conjunction with the Maintenance Division of the EP Dept., which must concur in the final estimate. The additional days required to perform operating and construction work prior to the start of, and after completion of, the maintenance work are then added to the outage days required for maintenance tasks. This process establishes the estimated outage durations required for each unit to meet the overall preventive maintenance program scheduled for the period under investigation.

The Electric Production Department's outage scheduling group then examines each unit's outage duration and schedules these outages for discrete time periods, giving considerations to the following:

1 - System reliability including coordination with outages of the transmission system

2 - System load requirements

3 - System economics

4 - Flows on the Susquehanna River

5 - Nuclear fuel burn-up considerations

6 - Station restrictions on simultaneous outages

7 - Overall Maintenance Division manpower constraints

The end result of this process is a projected system-wide outage schedule. The outage schedule is reviewed monthly and appropriate adjustments are made to reflect changes in work scope since the last review, changes in assigned time due to revised operating input, and any other factors that would necessitate a change in outage duration or timing.

Q. Mr. Carroll, you mentioned the fact that energy requirements, fuel price escalation rates, capacity additions and retirements and two-party purchase agreements are required inputs. How do you determine these inputs?

A. The energy requirements are received from Commercial Operations and are the Company's official projection of sales and associated energy output projections. The fuel price escalation rates are received from Fuel Procurement. The capacity additions and retirements are as provided by the System Planning Division and include the addition of Limerick No. 1 unit and the retirement of Southwark No. 1 and No. 2 units and the selected combustion turbines. The level of two-party purchase agreements is projected at the maximum two-party power available to the PJM due to transmission limitation considerations and PECO receives its allocated share according to the PJM allocation among the member companies. At present, this represents approximately 3000 mw to PJM and 430 mw to PECO.

Q. Mr. Carroll, turning to the final topic of your testimony, have you prepared certain sensitivity analyses to determine the impact of limitations on energy availability and fuel prices on PECO's total fuel and interchange expenses?

A. Yes, these analyses were performed under my direction.

Q. Would you explain how you determined the inputs used in these analyses.

A. There were five areas of energy availability and cost examined which could have a major impact on PECO's total fuel

and interchange expenses: (1) a reduction in hydro energy due to low natural water flow as the result of limited precipitation; (2) a reduction in nuclear generation on PJM; (3) a reduction in coal generation energy available to PJM; (4) reduced two-party purchases of Western coal energy; and (5) an increase in fossil fuel prices.

For the reduction in hydro energy, I examined the output from Conowingo dam for its entire history when 11 units were operating at this station. The annual output ranged from 1,117,223 MWH as a low to 2,275,193 MWH as a high with the average at 1,732,000 MWH which is our predicted value for the revised ECR. This information is tabulated on Schedule 2(a) to my testimony. A value of 1,224,000 was then selected as a possible low value for use in the Prod Cost program. Since Conowingo shares the same water with Holtwood and Safe Harbor, all three plants were reduced in output to the same percentage level of their normal value. As you will note in Schedule 2(a), this value is not the lowest historic output, but is very close to the second lowest year on record.

The second condition examined was nuclear generation. Again, history was used as a guide to a possible low. Schedule 2(b) shows the Nuclear Generation Capacity Factor experienced on PJM. These historical values do not reflect TMI experience

beyond 1978. A value of 49.9% was selected as a potential low nuclear output that could be repeated for all PJM units during the year, which is again not the lowest value experienced but is very close to the second lowest value.

The coal generation availability was reduced to reflect two separate conditions. First, if the Western coal generation available for two-party transactions was drastically reduced, it would have a significant impact on the entire PJM operating fuel expenses and on PECO's fuel and interchange expenses in particular. A joint study of East Central Area Reliability Coordination (ECAR) and Mid Atlantic Area Coordination (MAAC) has shown that the energy available from ECAR for MAAC is expected to start being reduced in the second half of the 1980's and by the early 1990's would be down to approximately 500 mw.

What PECO evaluated was, is there any possibility that this could happen in the near future and what would be the consequences? Upon review, it was felt that several conditions could accelerate this reduction in Western coal generation available to MAAC, as follows:

1 - Loss of one or more major generating units in the west for an extended period.

2 - Unexpected economic recovery in the ECAR region with its resultant energy requirements.

3 - A combination of these two.

4 - Either environmental or regional regulations that would limit the operation of coal fired capacity for energy needs outside the State or Region.

If these conditions did result in the reduction of reserve capacity in the West, it was felt that there was still a strong possibility that there would be a sharing of the operating reserve energy and, therefore, the Western coal fired energy for two-party transactions was reduced to 1,000 mw per hour with a 20% Forced Outage Rate applied.

The second part of the reduced coal energy availability was a consideration of the loss of generation from Eddystone Station, equivalent to one unit year combined with the remaining coal units on PJM remaining at their historical collective capacity factor. This condition was experienced in the past and it could possibly happen in the future as the result of a problem with the S02 removal system, MgO regeneration plants or EPA regulations.

Q. Mr. Carroll, you also mentioned the impact of fuel prices in your sensitivity analysis, what were the changes made to the fuel prices and what was the basis for these changes?

A. We examined the changes in fuel prices experienced in the past and found that during the 1973 to 1975 period and again in the 1979 to 1981 period, dramatic increases in fuel prices were experienced due to international market conditions. During these periods, oil and coal prices increased significantly as shown on Schedule 2(c). We looked at the annual rate of increase as if it was evenly spread over the three years (a less stringent rate of increase than was actually experienced) and applied this rate of inflation over the first year the new ECR will be in effect. Specifically, an escalation rate of 30% was applied to oil, somewhat less than the values shown on Schedule 2(c), and 11.7% to coal.

Q. Mr. Carroll, please continue with your description of how these five possible adverse conditions discussed above could affect PECO's total fuel and interchange expenses.

A. Two separate sensitivity scenarios employing these adverse conditions were analyzed. The Reduced Two Party Purchases and Higher Fuel Prices were included in both analyses. The analysis referred to as the Nuclear Generation Scenario also had low PJM Nuclear Energy and this reduced nuclear output was applied to all the presently commercially operating units on PJM. The analysis referred to as the Coal Generation Scenario combined the two common conditions (Reduced Two Party and High Fuel Prices) with Low Hydro Energy and Low PJM Coal Availability.

Q. What was the impact on PECO's total fuel and interchange expenses as a result of the combination of adverse conditions which you analyzed?

A. If the conditions represented by the Nuclear Generation Scenario were experienced during the first year the ECR is in effect, PECO's total fuel and interchange expenses would increase by $129.5 million or approximately 29%. If the conditions represented by the Coal Generation Scenario were experienced during the first year the new ECR will be in effect, PECO's total fuel and interchange expenses would increase by $108.9 million or approximately 24%. Moreover, the impact of these scenarios increases over time as the absolute magnitude of energy costs increases. Specifically, the impact of the Nuclear Generation Scenario is $141.3 million in year 2 and $232.2 million in year 3. Similarly, the impact of the Coal Generation Scenario is $137.4 million in year 2 and $136.8 million in year 3.

Q. Is PECO predicting that any of the conditions used in either the Nuclear Generation or Coal Generation Scenarios will actually happen in the first new ECR year?

A. No, PECO is not predicting that any of the unusual conditions inputted to the Nuclear Generation or Coal Generation Scenarios will actually happen; rather, PECO is predicting

the conditions of Fuel Cost, Hydro Generation, Nuclear Unit Availability and Coal Unit Availability as shown in Exhibit JJC-1, Item 3(i). However, if adverse circumstances were to be encountered with respect to either or each of these natural, international and regulatory conditions which impact unit operation, but which are beyond PECO's control, one of the analyzed Scenarios could well be experienced during the analysis period. Again, I should emphasize that each of these adverse conditions and the combinations which I have presented are very real possibilities based on current conditions and in light of historic experience.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

WESTINGHOUSE UNIT CAPACITY FACTORS (MDC)

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	AVG.	WT.AVG.
TURKEY POINT 3	PWR	WE	WE	666	693	12	72	77.3	16.1	66.5	74.9	81.8	5	63.3	316.6
SURRY 1	PWR	WE	WE	775	788	12	72	36.3	35.0	80.8	51.8	49.0	5	50.6	252.9
SURRY 2	PWR	WE	WE	775	788	5	73	32.9	75.9	80.9	60.2	76.5	5	65.3	326.4
TURKEY POINT 4	PWR	WE	WE	666	693	9	73	67.9	79.6	67.9	51.5	52.6	5	63.9	319.5
INDIAN POINT 2	PWR	WE	WE	864	873	8	74	56.7	40.7	58.8	78.3	38.4	5	54.6	272.9
INDIAN POINT 3	PWR	WE	WE	965	965	8	76	36.2	35.9	18.4	0.7	71.3	5	32.5	162.5
SALEM 1	PWR	WE	WE	1079	1090	6	77	60.0	65.5	43.3	56.9	22.4	5	49.6	248.1
SALEM 2	PWR	WE	WE	1106	1115	10	81			82.0	7.7	32.9	3	40.9	122.6
WESTINGHOUSE AVERAGES								52.5	49.8	62.3	47.8	53.1	38		53.2

OVERALL AVG. 53.2
SALEM AVG. 46.3
AVG. W/O SALEM 55.0

20-Dec-85

GENERAL ELECTRIC BWR CAPACITY FACTORS (MDC)

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	AVG.	WT.AVG.
DRESDEN 2	BWR3	GE	GE	772	794	6	70	67.6	50.4	75.8	50.2	65.8	5	62.0	309.8
DRESDEN 3	BWR3	GE	GE	773	794	11	71	63.8	76.5	57.4	61.3	31.0	5	58.0	290.0
QUAD CITIES 1	BWR3	GE	GE	769	789	2	73	51.0	85.0	48.2	85.7	49.6	5	63.9	319.5
QUAD CITIES 2	BWR3	GE	GE	769	789	3	73	53.5	55.9	75.1	46.8	73.8	5	61.0	305.1
BROWNS FERRY 1	BWR4	GE	GE	1065	1065	8	74	64.8	47.2	84.5	23.3	83.9	5	60.7	303.7
BROWNS FERRY 2	BWR4	GE	GE	1065	1065	3	75	60.1	80.1	47.7	68.4	43.2	5	59.9	299.5
FITZPATRICK	BWR4	GE	GE	810	821	7	75	60.1	67.4	69.9	65.3	68.9	5	66.3	331.6
BRUNSWICK 2	BWR4	GE	GE	790	821	11	75	26.9	47.5	27.6	56.9	20.1	5	35.8	179.0
HATCH 1	BWR4	GE	GE	752	777	12	75	71.4	41.6	43.3	59.2	54.5	5	54.0	270.0
BROWNS FERRY 3	BWR4	GE	GE	1065	1065	3	77	74.1	67.1	52.4	57.8	3.1	5	50.9	254.5
BRUNSWICK 1	BWR4	GE	GE	790	821	3	77	56.8	36.9	42.2	20.1	72.5	5	45.7	228.5
HATCH 2	BWR4	GE	GE	748	784	9	79	53.7	66.2	55.2	56.4	28.5	5	52.0	260.0
PEACH BOTTOM 2	BWR4	GE	GE	1051	1065	7	74	47.1	72.0	52.1	48.3	26.3	5	49.2	245.8
PEACH BOTTOM 3	BWR4	GE	GE	1035	1065	12	74	79.6	34.5	94.1	26.7	81.9	5	63.4	316.8
G. E. BWR AVERAGES								58.7	60.2	56.6	54.3	49.6	60		55.9

OVERALL AVG. 55.91
PEACH BOTM AVG 56.26
AVG. W/O P.BTM 55.85

UNIT AVAILABILITY FACTORS 1980-1984

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
TURKEY POINT 3	PWR	WE	WE	666	693	12	72	77.6	15.8	64.1	73.3	82.6	5	62.7
SURRY 1	PWR	WE	WE	775	788	12	72	44.9	38.9	88.8	57.2	58.5	5	57.7
SURRY 2	PWR	WE	WE	775	788	5	73	35.8	79.6	88.3	65.4	83.5	5	70.5
TURKEY POINT 4	PWR	WE	WE	666	693	9	73	69.5	77.7	66.3	52.2	54.4	5	64.0
INDIAN POINT 2	PWR	WE	WE	864	873	8	74	64.8	46.0	65.4	84.0	51.9	5	62.4
INDIAN POINT 3	PWR	WE	WE	965	965	8	76	53.2	59.8	22.5	2.6	76.3	5	42.9
SALEM 1	PWR	WE	WE	1079	1090	6	77	69.2	78.1	47.9	58.6	27.1	5	56.2
SALEM 2	PWR	WE	WE	1106	1115	10	81	N.A.	94.6	97.3	12.3	36.4	4	60.2
													39	
YEARLY AVERAGES								59.3	61.3	67.6	50.7	58.8		

OVERALL AVG. 59.55
SALEM AVG. 57.94
AVG. W/O SALEM 60.03

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
DRESDEN 2	BWR3	GE	GE	772	794	6	70	93.3	60.1	92.4	58.0	72.9	5	75.3
DRESDEN 3	BWR3	GE	GE	773	794	11	71	71.8	94.3	63.5	73.1	37.7	5	68.1
QUAD CITIES 1	BWR3	GE	GE	769	789	2	73	66.5	94.1	68.0	94.3	53.4	5	75.3
QUAD CITIES 2	BWR3	GE	GE	769	789	3	73	62.5	68.0	83.9	64.2	77.9	5	71.3
BROWNS FERRY 1	BWR4	GE	GE	1065	1065	8	74	72.6	50.7	91.0	26.5	90.3	5	66.2
BROWNS FERRY 2	BWR4	GE	GE	1065	1065	3	75	69.2	85.1	54.5	74.4	66.5	5	69.9
FITZPATRICK	BWR4	GE	GE	810	821	7	75	70.2	74.7	75.0	70.6	76.8	5	73.5
BRUNSWICK 2	BWR4	GE	GE	790	821	11	75	35.2	66.3	38.6	64.3	25.5	5	46.0
HATCH 1	BWR4	GE	GE	752	777	12	75	81.7	50.1	49.3	71.3	62.3	5	62.9
BROWNS FERRY 3	BWR4	GE	GE	1065	1065	3	77	79.1	72.6	57.3	61.9	5.9	5	55.4
BRUNSWICK 1	BWR4	GE	GE	790	821	3	77	68.9	47.5	62.0	24.2	77.4	5	56.0
HATCH 2	BWR4	GE	GE	748	784	9	79	60.0	78.5	63.8	65.9	32.3	5	60.1
PEACH BOTTOM 2	BWR4	GE	GE	1051	1065	7	74	51.6	79.3	58.1	50.9	29.0	5	53.8
PEACH BOTTOM 3	BWR4	GE	GE	1035	1065	12	74	80.7	36.6	95.6	31.0	85.9	5	66.0
													70	
YEARLY AVERAGES								68.8	68.4	68.1	59.3	56.7		

OVERALL AVG. 64.27
PEACH BOTM AVG 59.87
AVG. W/O P.BTM 65.00

FORCED OUTAGE HOURS 1980-1984

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
TURKEY POINT 3	PWR	WE	WE	666	693	12	72	N.A	1523.2	724.9	131.0	958.5	4	834.4
SURRY 1	PWR	WE	WE	775	788	12	72	N.A	458.8	323.3	223.2	222.0	4	306.8
SURRY 2	PWR	WE	WE	775	788	5	73	N.A	65.7	193.8	102.3	1087.3	4	362.3
TURKEY POINT 4	PWR	WE	WE	666	693	9	73	N.A	248.0	778.6	552.3	1496.3	4	768.8
INDIAN POINT 2	PWR	WE	WE	864	873	8	74	N.A	992.7	454.1	381.9	792.4	4	655.3
INDIAN POINT 3	PWR	WE	WE	965	965	8	76	N.A	3065.3	45.6	4715.5	870.3	4	2174.2
SALEM 1	PWR	WE	WE	1079	1090	6	77	N.A	1915.9	308.0	3630.0	3851.7	4	2426.4
SALEM 2	PWR	WE	WE	1106	1115	10	81	N.A	103.3	240.5	3839.3	5589.2	4	2443.1
													32	
YEARLY AVERAGES								N.A	1046.6	383.6	1696.9	1858.5		

OVERALL AVG. 1246.40
SALEM AVG. 2434.74
AVG. W/O SALEM 850.29

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	YRS	AVG.
DRESDEN 2	BWR3	GE	GE	772	794	6	70	N.A	430.3	556.0	1075.5	289.8	4	587.9
DRESDEN 3	BWR3	GE	GE	773	794	11	71	N.A	438.8	268.9	144.5	547.5	4	349.9
QUAD CITIES 1	BWR3	GE	GE	769	789	2	73	N.A	181.6	115.1	114.5	127.8	4	134.8
QUAD CITIES 2	BWR3	GE	GE	769	789	3	73	N.A	66.4	1257.4	28.2	436.6	4	447.2
BROWNS FERRY 1	BWR4	GE	GE	1065	1065	8	74	N.A	168.3	737.5	204.0	820.0	4	482.5
BROWNS FERRY 2	BWR4	GE	GE	1065	1065	3	75	N.A	799.5	280.3	368.1	249.4	4	424.3
FITZPATRICK	BWR4	GE	GE	810	821	7	75	N.A	732.5	556.5	335.4	323.3	4	486.9
BRUNSWICK 2	BWR4	GE	GE	790	821	11	75	N.A	2607.1	1477.9	946.9	544.8	4	1394.2
HATCH 1	BWR4	GE	GE	752	777	12	75	N.A	649.1	1520.6	375.3	967.7	4	878.2
BROWNS FERRY 3	BWR4	GE	GE	1065	1065	3	77	N.A	487.9	1300.3	558.0	863.0	4	802.3
BRUNSWICK 1	BWR4	GE	GE	790	821	3	77	N.A	1194.6	2625.0	138.8	632.2	4	1147.7
HATCH 2	BWR4	GE	GE	748	784	9	79	N.A	589.7	726.0	1169.9	238.6	4	681.1
PEACH BOTTOM 2	BWR4	GE	GE	1051	1065	7	74	N.A	1616.0	165.4	3427.3	116.4	4	1331.3
PEACH BOTTOM 3	BWR4	GE	GE	1035	1065	12	74	N.A	444.4	386.0	141.3	764.2	4	434.0
YEARLY AVERAGES								N.A	743.30	855.21	644.84	494.38	56	

OVERALL AVG. 684.43
PEACH BOTM AVG 882.63
AVG. W/O P.BTM 651.40

UNIT FORCED OUTAGE RATES 1980-1984

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
TURKEY POINT 3	PWR	WE	WE	666	693	12	72	1.5	52.4	11.4	2.0	11.7	5	15.8
SURRY 1	PWR	WE	WE	775	788	12	72	39.1	11.9	4.0	4.3	4.1	5	12.7
SURRY 2	PWR	WE	WE	775	788	5	73	3.1	0.9	2.4	1.8	12.9	5	4.2
TURKEY POINT 4	PWR	WE	WE	666	693	9	73	0.3	3.5	11.8	10.8	23.8	5	10.0
INDIAN POINT 2	PWR	WE	WE	864	873	8	74	15.3	19.8	7.3	4.9	14.8	5	12.4
INDIAN POINT 3	PWR	WE	WE	965	965	8	76	24.1	36.9	2.3	95.4	11.5	5	34.0
SALEM 1	PWR	WE	WE	1079	1090	6	77	5.6	21.9	6.8	41.4	61.8	5	27.5
SALEM 2	PWR	WE	WE	1106	1115	10	81	N.A.	5.4	2.7	78.0	63.6	4	37.4
													39	
YEARLY AVERAGES								12.7	19.1	6.1	29.8	25.5		

OVERALL AVG.	18.80
SALEM AVG.	31.91
AVG. W/O SALEM	14.87

UNIT NAME & #	RCTR TYPE	MANUFACT. RCTR	MANUFACT. TURB	CAPACITY MDC	CAPACITY DER	COMM. DATE MTH	COMM. DATE YR	80	81	82	83	84	LAST 5 YEAR AVERAGE YRS	LAST 5 YEAR AVERAGE AVG.
DRESDEN 2	BWR3	GE	GE	772	794	6	70	4.4	7.6	6.4	17.5	4.3	5	8.0
DRESDEN 3	BWR3	GE	GE	773	794	11	71	2.5	5.0	4.6	2.2	14.2	5	5.7
QUAD CITIES 1	BWR3	GE	GE	769	789	2	73	4.2	2.2	1.9	1.4	2.7	5	2.5
QUAD CITIES 2	BWR3	GE	GE	769	789	3	73	8.3	1.1	14.6	0.5	6.0	5	6.1
BROWNS FERRY 1	BWR4	GE	GE	1065	1065	8	74	7.5	3.7	8.5	8.1	9.4	5	7.4
BROWNS FERRY 2	BWR4	GE	GE	1065	1065	3	75	10.8	9.7	5.5	5.3	4.1	5	7.1
FITZPATRICK	BWR4	GE	GE	810	821	7	75	4.0	10.1	7.8	5.1	4.6	5	6.3
BRUNSWICK 2	BWR4	GE	GE	790	821	11	75	16.1	31.0	30.4	14.4	19.6	5	22.3
HATCH 1	BWR4	GE	GE	752	777	12	75	18.1	12.9	26.1	5.7	15.0	5	15.6
BROWNS FERRY 3	BWR4	GE	GE	1065	1065	3	77	11.7	7.1	20.6	9.3	63.1	5	22.4
BRUNSWICK 1	BWR4	GE	GE	790	821	3	77	8.2	22.3	32.6	6.1	8.5	5	15.5
HATCH 2	BWR4	GE	GE	748	784	9	79	12.4	7.9	11.5	16.8	7.8	5	11.3
PEACH BOTTOM 2	BWR4	GE	GE	1051	1065	7	74	4.0	18.9	3.1	43.4	4.4	5	14.8
PEACH BOTTOM 3	BWR4	GE	GE	1035	1065	12	74	11.0	12.2	4.4	4.9	9.2	5	8.3
													70	
YEARLY AVERAGES								8.8	10.8	12.7	13.2	12.4		

OVERALL AVG.	10.95
PEACH BOTM AVG	11.55
AVG. W/O P.BTM	10.85

Conowingo Annual Output

MWH

Year	MWH Output
1965	1,117,223
1966	1,303,458
1967	1,894,731
1968	1,585,765
1969	1,342,128
1970	1,876,803
1971	1,737,834
1972	2,242,533
1973	2,131,912
1974	1,937,729
1975	2,275,193
1976	2,065,359
1977	1,996,723
1978	1,700,078
1979	2,154,921
1980	1,239,494
1981	1,396,799
1982	1,581,431
1983	1,738,785
1984	2,084,881

PJM Nuclear Unit Combined Capacity Factor

Year	% Capacity Factor	No. of Units
1970	74.4	1
1971	77.5	1
1972	80.0	1
1973	64.0	1
1974	67.6	1
1975	66.3	5
1976	69.3	5
1977	59.8	7
1978	69.1	7
1979	58.6	7
1980	63.4	7
1981	63.3	7
1982	65.9	7
1983	46.9	8
1984	49.8	8

Fuel Sensitivity Analysis
Historical Data

Coal

1973 through 1975

	Eddystone	Cromby
11-20-72	53.19	51.23
12-22-75	126.49	137.97
Ratio	2.378	2.693

Approx. Wt. Avg. 2.441
Equiv. Annual Factor 1.346

1978 through 1980

	Eddystone	Cromby
11-30-77	117.81	129.10
12-12-80	166.03	169.42
	1.4093	1.3123

1.3899
1.116

Oil #6

Loc.	11-20-72	12-22-75	Ratio	11-23-77	12-12-80	Ratio
Schuyl.	75.37	203.99	2.707	221.78	543.47	2.45
Cromby	79.34	203.85	2.569	228.95	538.19	2.351
Chester	73.54	199.63	2.715	222.46	548.43	2.465
Delaware	73.54	199.63	2.715	222.46	548.43	2.465
Richmond	73.54	199.63	2.715	222.46	548.43	2.465
Barbadoes	79.18	209.77	2.65	-	-	-
Southwrk.	73.54	199.63	2.715	222.46	548.43	2.465
Eddystone	-	-	-	222.46	548.43	2.465
Approx. Wt. Avg.			2.68			2.447
Equiv. Annual Factor			1.39			1.347

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

EXHIBIT TO ACCOMPANY
SUPPLEMENTAL DIRECT TESTIMONY
OF
JOHN J. CARROLL

DATA REQUIREMENTS OF ECR NO. 8 ORDER, APPENDIX B

DOCKETED
JAN 2 - 1986

December 1985

DOCUMENT
FOLDER

Data Request (1), Data Request (1) (i)

Projected Energy Supply Mix
Projected Energy Prices
Information Provided Monthly by Class,
Unit, on a Monthly Basis

TRIC GENERATION AND FUEL COST ESTIMATES	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
-PE STM.	153,000	146,000	146,000	114,000	146,000	186,000
-PE STM.	269,000	316,000	204,000	200,000	185,000	220,000
-MINEMTH	372,000	374,000	365,000	383,000	336,000	339,000
COMB.	17,220	32,910	14,980	7,590	7,810	4,240
L FOSSIL	811,220	868,910	729,980	704,590	674,810	749,240
NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
HYDRO	24,000	(7,000)	1,000	49,000	76,000	144,000
ER	0	0	0	0	0	0
IVED PJM	234,000	213,000	301,000	182,000	295,000	294,000
V'D PJM	(128,000)	(174,000)	(95,000)	(80,000)	(104,000)	(98,000)
M-HT PP	500	2,500	2,700	3,900	8,500	16,500
PL & DPL	16	16	16	16	16	16
TY TRANS	173,000	175,000	174,000	191,000	192,000	208,000
H & PUR	279,516	216,516	382,716	296,916	391,516	420,516
L OUTPUT	2,864,414	2,798,423	2,462,148	2,344,868	2,385,407	2,621,360
PE STM	8,291,000	7,906,000	8,068,000	6,730,000	8,006,000	10,020,000
-PE STM	5,537,000	6,504,000	4,206,000	4,175,000	3,884,000	4,661,000
EMOUTH	5,202,000	5,272,000	5,168,000	5,460,000	4,804,000	4,897,000
COMB	1,120,000	2,168,800	966,400	475,500	493,500	262,500
L FOSSIL	20,158,000	21,850,800	18,408,400	16,840,500	17,187,500	19,840,500
LEAR EXCLUDING INTEREST, BUT INCLUDING OIL)						
LEAR.	12,899,724	12,713,952	10,067,749	9,915,663	9,442,991	9,990,157
ER	0	0	0	0	0	0
IVED PJM	7,014,000	7,470,000	9,825,000	7,172,000	9,080,000	10,142,000
V'D PJM	(5,636,000)	(7,447,000)	(4,149,000)	(3,135,000)	(5,235,000)	(4,695,000)
M-HT PP	17,000	87,000	96,000	142,000	307,000	646,000
PL & DPL	1,196	1,196	1,196	1,196	1,196	1,196
TY TRANS	5,225,000	5,295,000	5,261,000	5,891,000	5,921,000	6,394,000
H & PUR	6,621,196	5,406,196	11,034,196	10,071,196	10,074,196	12,488,196
RMATION FOR RATE DIVISION ($'S EXCLUDE FUEL HANDLING)						
N.CHGS	39,678,920	39,970,948	39,510,345	36,827,359	36,704,687	42,318,853
CHGS	1,552,217	1,499,325	1,446,433	1,404,175	1,361,918	1,592,040
N.CHGS	41,231,137	41,470,273	40,956,778	38,231,534	38,066,605	43,910,893
$ INCLUDED IN COAL-PE STM)						
L GAS	537,000	632,000	357,000	317,000	108,000	0
RMATION FOR GEN. ACC. BUDGET GRP. (TOTAL FUEL HAND. $)						
L HANDL'G	839,735	831,978	812,520	816,886	810,367	810,703

TRIC GENERATION AND FUEL COST ESTIMATES

Page 2

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
E STM.	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
PE STM.	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
MINEMTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
OMB.	11,770	12,380	2,610	12,280	2,240	4,230	130,260
FOSSIL	1,005,770	760,380	715,610	668,280	739,240	743,230	9,171,260
UCLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
YDRO	99,000	131,000	213,000	225,000	160,000	79,000	1,194,000
	0	0	0	0	0	0	0
VED PJM	136,000	282,000	259,000	418,000	387,000	725,000	3,726,000
D PJM	(336,000)	(113,000)	(148,000)	(14,000)	(23,000)	(4,000)	(1,317,000)
-HT PP	22,200	15,600	12,100	5,100	1,900	2,300	93,800
& DPL	16	16	16	16	16	16	192
TRANS	187,000	166,000	172,000	156,000	141,000	144,000	2,079,000
& PUR	9,216	350,616	295,116	565,116	506,916	867,316	4,581,992
OUTPUT	2,729,324	2,436,967	2,506,516	2,261,193	2,321,348	2,554,526	30,286,494
STM	15,134,000	8,923,000	6,507,000	5,958,000	4,788,000	7,531,000	97,862,000
E STM	7,667,000	5,975,000	6,435,000	5,811,000	5,670,000	5,412,000	65,937,000
UTH	5,329,000	4,578,000	4,283,000	4,260,000	5,848,000	5,230,000	60,331,000
MB	801,000	807,700	169,800	860,000	148,000	292,000	8,573,200
FOSSIL	28,931,000	20,283,700	17,394,800	16,889,000	16,454,000	18,465,000	232,703,200
AR EXCLUDING INTEREST, BUT INCLUDING OIL)							
R.	12,152,686	9,143,637	9,859,519	5,990,617	6,791,025	6,357,607	115,325,327
	0	0	0	0	0	0	0
ED PJM	5,123,000	11,222,000	8,415,000	12,257,000	11,702,000	23,748,000	123,170,000
PJM	(17,798,000)	(6,301,000)	(6,655,000)	(764,000)	(725,000)	(237,000)	(62,777,000)
NT PP	1,006,000	656,000	434,000	173,000	60,000	78,000	3,702,000
& DPL	1,280	1,280	1,280	1,280	1,280	1,280	14,856
TRANS	5,852,000	5,199,000	5,392,000	4,939,000	4,471,000	4,558,000	64,398,000
PUR	(5,815,720)	10,777,280	7,587,280	16,606,280	15,509,280	28,148,280	128,507,856
TION FOR RATE DIVISION ($'S EXCLUDE FUEL HANDLING)							
HGS	35,267,966	40,204,617	34,841,599	39,485,897	38,754,305	52,970,887	476,536,383
S	1,546,272	1,500,504	1,786,919	1,723,429	1,673,874	1,624,317	18,711,423
HGS	36,814,238	41,705,121	36,628,518	41,209,326	40,428,179	54,595,204	495,247,806
INCLUDED IN COAL-PE STM)							
AS	0	0	41,000	596,000	586,000	485,000	3,659,000
TION FOR GEN. ACC. BUDGET GRP. (TOTAL FUEL HAND. $)							
NDL'G	0	0	0	0	0	0	4,922,189

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
IL						
E REHEAT OIL						
CHUYLKILL#1	25,000	21,000	24,000	5,000	22,000	22,000
DDYSTONE#3	48,000	33,000	40,000	41,000	34,000	42,000
DDYSTONE#4	43,000	51,000	50,000	36,000	32,000	30,000
RONBY#2	0	0	0	0	40,000	53,000
ELAWARE#7	20,000	20,000	17,000	19,000	17,000	20,000
ELAWARE#8	17,000	21,000	15,000	13,000	1,000	19,000
H R H OIL	153,000	146,000	146,000	114,000	146,000	186,000
MARGINAL OIL						
CHMOND#9	0	0	0	0	0	0
UTHWARK#1	0	0	0	0	0	0
UTHWARK#2	0	0	0	0	0	0
H MARG OIL	0	0	0	0	0	0
EAT & MARGINAL OIL						
OIL	153,000	146,000	146,000	114,000	146,000	186,000
COAL						
YSTONE#1	104,000	118,000	115,000	129,000	121,000	106,000
YSTONE#2	115,000	139,000	30,000	0	0	40,000
MBY#1	50,000	59,000	59,000	71,000	64,000	74,000
COAL	269,000	316,000	204,000	200,000	185,000	220,000
LA. AREA OIL AND COAL.						
LA STEAM	422,000	462,000	350,000	314,000	331,000	406,000
- STATION TOTALS						
YSTONE	310,000	341,000	235,000	206,000	187,000	218,000
BY	50,000	59,000	59,000	71,000	104,000	127,000
WARE7&8	37,000	41,000	32,000	32,000	18,000	39,000
THWARK1&2	0	0	0	0	0	0

STRIBUTION 1 OF 4

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
EAT OIL							
KILL#1	45,000	24,000	21,000	14,000	9,000	14,000	246,000
ONE#3	67,000	18,000	12,000	24,000	16,000	37,000	412,000
ONE#4	66,000	62,000	13,000	12,000	20,000	20,000	435,000
#2	44,000	12,000	44,000	32,000	25,000	38,000	288,000
RE#7	34,000	19,000	12,000	10,000	3,000	12,000	203,000
RE#8	21,000	21,000	11,000	10,000	5,000	11,000	165,000
H OIL	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
GINAL OIL							
ND#9	0	0	0	0	0	0	0
ARK#1	0	0	0	0	0	0	0
ARK#2	0	0	0	0	0	0	0
RG OIL	0	0	0	0	0	0	0
& MARGINAL OIL							
L	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
L							
ONE#1	124,000	111,000	108,000	117,000	110,000	101,000	1,364,000
ONE#2	147,000	98,000	133,000	126,000	130,000	97,000	1,055,000
#1	84,000	68,000	55,000	28,000	24,000	53,000	689,000
AL	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
AREA OIL AND COAL.							
STEAM	632,000	433,000	409,000	373,000	342,000	383,000	4,857,000
STATION TOTALS							
ONE	404,000	289,000	266,000	279,000	276,000	255,000	3,266,000
	128,000	80,000	99,000	60,000	49,000	91,000	977,000
RE7&8	55,000	40,000	23,000	20,000	8,000	23,000	368,000
ARK1&2	0	0	0	0	0	0	0

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
INEMOUTH (PE SHARE)						
EYSTONE#1	107,000	108,000	95,000	109,000	94,000	90,000
EYSTONE#2	96,000	84,000	88,000	96,000	85,000	90,000
EYSTONE STA	203,000	192,000	183,000	205,000	179,000	180,000
ONEMAUGH#1	81,000	96,000	87,000	86,000	79,000	85,000
ONEMAUGH#2	88,000	86,000	95,000	92,000	78,000	74,000
ONEMAUGHSTA	169,000	182,000	182,000	178,000	157,000	159,000
INEMOUTH	372,000	374,000	365,000	383,000	336,000	339,000
HILA. AREA OIL & COAL, AND MINEMOUTH COAL.						
OSSIL STEAM	794,000	836,000	715,000	697,000	667,000	745,000
CLEAR (PE SHARE)						
ACH BOT#2	258,117	281,339	252,759	216,140	290,270	208,102
ACH BOT#3	229,561	272,658	206,693	188,222	132,811	266,502
H BOT STA	487,678	553,997	459,452	404,362	423,081	474,604
LEM#1	282,000	264,000	242,000	247,000	274,000	247,000
LEM#2	317,000	273,000	136,000	0	0	21,000
LEM STA	599,000	537,000	378,000	247,000	274,000	268,000
M1	663,000	629,000	511,000	643,000	546,000	565,000
M2	0	0	0	0	0	0
M STA	663,000	629,000	511,000	643,000	546,000	565,000
H NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
HER (PRECOMMERCIAL)						
MERICK 1	0	0	0	0	0	0
MERICK 2	0	0	0	0	0	0
HER	0	0	0	0	0	0

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
IEMOUTH (PE SHARE)							
STONE#1	93,000	90,000	111,000	21,000	84,000	101,000	1,103,000
STONE#2	81,000	81,000	94,000	92,000	107,000	92,000	1,086,000
STONE STA	174,000	171,000	205,000	113,000	191,000	193,000	2,189,000
EHAUGH#1	96,000	82,000	93,000	87,000	102,000	86,000	1,060,000
EHAUGH#2	92,000	62,000	6,000	83,000	102,000	77,000	935,000
EHAUGHSTA	188,000	144,000	99,000	170,000	204,000	163,000	1,995,000
EMOUTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
LA. AREA OIL & COAL, AND MINEMOUTH COAL.							
IL STEAM	994,000	748,000	713,000	656,000	737,000	739,000	9,041,000
EAR (PE SHARE)							
H BOT#2	276,873	14,290	0	0	248,293	275,980	2,322,163
H BOT#3	259,465	228,681	237,790	246,797	156,899	0	2,426,079
BOT STA	536,338	242,971	237,790	246,797	405,192	275,980	4,748,242
H#1	263,000	257,000	283,000	281,000	300,000	287,000	3,227,000
H#2	255,000	209,000	207,000	275,000	210,000	302,000	2,205,000	
1 STA	518,000	466,000	490,000	556,000	510,000	589,000	5,432,000
	561,000	486,000	555,000	0	0	0	5,159,000
TA	0	0	0	0	0	0	0
	561,000	486,000	555,000	0	0	0	5,159,000
UCLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
(PRECOMMERCIAL)							
ICK 1	0	0	0	0	0	0	0
ICK 2	0	0	0	0	0	0	0
	0	0	0	0	0	0	0

I DISTRIBUTION 3 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
ESELS						
ONBY D 1&2	20	0	0	0	100	40
LAWARE D	20	20	0	20	40	0
UTHWARK D	0	0	0	0	0	0
HUYLKILL D	0	0	20	10	0	0
DIESELS	40	20	20	30	140	40
YSTONE D	10	20	20	0	0	0
NEMAUGH D	10	20	20	0	0	0
ESEL	60	60	60	30	140	40
S TURBINES						
CH GE CT	2,750	6,170	2,240	1,060	1,770	0
CH HE CT	0	0	0	0	0	0
CH NO CT	0	0	0	0	0	0
CHCT TOTAL	2,750	6,170	2,240	1,060	1,770	0
UTHWARK CT	210	870	400	0	0	0
DYSTONE CT	280	880	360	0	0	0
LAWARE CT	270	830	400	0	0	0
HUYLKILLCT	110	480	100	0	0	0
ESTER CT	210	630	300	0	0	0
LLS CT	360	790	360	0	0	0
SER CT	240	840	330	0	0	0
Y MIG CT	0	0	0	0	0	0
SUBTOTAL	4,430	11,490	4,490	1,060	1,770	0
ROYDON	12,700	21,300	10,400	6,500	5,900	4,200
AS TURBINES	17,130	32,790	14,890	7,560	7,670	4,200
ALEM CT	30	60	30	0	0	0
OTAL CT	17,160	32,850	14,920	7,560	7,670	4,200
OTAL CT AND DIESEL OTAL IC	17,220	32,910	14,980	7,590	7,810	4,240
IMPLE CYCLE (INC. SALEM CT) T TOTAL	4,460	11,550	4,520	1,060	1,770	0

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
SELS							
BY D 1&2	0	60	10	0	0	0	230
WARE D	170	40	0	60	0	0	370
THMARK D	0	0	0	0	0	0	0
YLKILL D	40	0	0	0	0	0	70
DIESELS	210	100	10	60	0	0	670
STONE D	0	0	0	10	0	0	60
EMAUGH D	0	0	0	10	0	0	60
SEL	210	100	10	80	0	0	790
TURBINES							
GE CT	860	280	0	2,830	240	930	19,130
NE CT	0	0	0	0	0	0	0
NO CT	0	0	0	0	0	0	0
CT TOTAL	860	280	0	2,830	240	930	19,130
THMARK CT	0	0	0	120	0	0	1,600
STONE CT	0	0	0	150	0	0	1,670
WARE CT	0	0	0	330	0	0	1,830
YLKILLCT	0	0	0	30	0	0	720
STER CT	0	0	0	180	0	0	1,320
S CT	0	0	0	220	0	0	1,730
R CT	0	0	0	210	0	0	1,620
MTG CT	0	0	0	0	0	0	0
BTOTAL	860	280	0	4,070	240	930	29,620
DON	10,700	12,000	2,600	8,100	2,000	3,300	99,700
TURBINES	11,560	12,280	2,600	12,170	2,240	4,230	129,320
M CT	0	0	0	30	0	0	150
L CT	11,560	12,280	2,600	12,200	2,240	4,230	129,470
L CT AND DIESEL							
L IC	11,770	12,380	2,610	12,280	2,240	4,230	130,260
LE CYCLE (INC. SALEM CT)							
OTAL	860	280	0	4,100	240	930	29,770

NH DISTRIBUTION 4 OF 4 (SUMMARY)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
L STEAM	153,000	146,000	146,000	114,000	146,000	186,000
COAL STEAM	269,000	316,000	204,000	200,000	185,000	220,000
NEWOUTH	372,000	374,000	365,000	383,000	336,000	339,000
SSIL STEAM	794,000	836,000	715,000	697,000	667,000	745,000
H NUCLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
HER	0	0	0	0	0	0
ESEL	60	60	60	30	140	40
TAL CT	17,160	32,850	14,920	7,560	7,670	4,200
T INTCH	106,000	39,000	206,000	102,000	191,000	196,000
R POWER	516	2,516	2,716	3,916	8,516	16,516
ARTY TRANS	173,000	175,000	174,000	191,000	192,000	208,000
DOMINGO	79,000	57,000	52,000	85,000	123,000	181,000
DY RUN	143,000	112,000	114,000	95,000	81,000	106,000
INPUT	(198,000)	(176,000)	(165,000)	(131,000)	(128,000)	(143,000)
AL OUTPUT	2,864,414	2,798,423	2,462,148	2,344,868	2,385,407	2,621,360

TE: THIS PAGE EXCLUDES SALEM #2 WHILE SOLD TO J.C.

PH DISTRIBUTION 4 OF 4 (SUMMARY)

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
L STEAM	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
COAL STEAM	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
MENOUTH	362,000	315,000	304,000	283,000	395,000	356,000	4,184,000
SIL STEAM	994,000	748,000	713,000	656,000	737,000	739,000	9,041,000
NUCLEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
ER	0	0	0	0	0	0	0
SEL	210	100	10	80	0	0	790
L CT	11,560	12,280	2,600	12,200	2,240	4,230	129,470
INTCH	(200,000)	169,000	111,000	404,000	364,000	721,000	2,409,000
POWER	22,216	15,616	12,116	5,116	1,916	2,316	93,992
TY TRANS	187,000	166,000	172,000	156,000	141,000	144,000	2,079,000
NINGO	138,000	172,000	259,000	258,000	205,000	123,000	1,732,000
' RUN	90,000	91,000	96,000	81,000	80,000	116,000	1,205,000
NPUT	(129,000)	(132,000)	(142,000)	(114,000)	(125,000)	(160,000)	(1,743,000)
OUTPUT	2,729,324	2,436,967	2,506,516	2,261,193	2,321,348	2,554,526	30,286,494

THIS PAGE EXCLUDES SALEM #2 WHILE SOLD TO J.C.

. COST 1 OF 4

(NO.6 & NO. 2)	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
YLKILL#1	1,146,000	936,000	1,122,000	227,000	1,015,000	1,059,000
'STONE1&2	182,000	166,000	186,000	195,000	164,000	210,000
'STONE3&4	5,185,000	4,852,000	5,147,000	4,643,000	4,086,000	4,460,000
1,2,3,4	5,367,000	5,018,000	5,333,000	4,838,000	4,250,000	4,670,000
SULFUR)	0	0	0	0	224,000	424,000
STONE	5,367,000	5,018,000	5,333,000	4,838,000	4,474,000	5,094,000
BY#1	16,000	14,000	14,000	11,000	11,000	10,000
BY#2	35,000	35,000	34,000	36,000	1,800,000	2,364,000
SULFUR)	135,000	160,000	159,000	198,000	178,000	205,000
BY	186,000	209,000	207,000	245,000	1,989,000	2,579,000
NARE 7&8	1,727,000	1,903,000	1,565,000	1,618,000	930,000	1,917,000
NOND	0	0	0	0	0	0
NMARK1&2	0	0	0	0	0	0
L OIL	8,426,000	8,066,000	8,227,000	6,928,000	8,408,000	10,649,000
STONE#1	1,880,000	2,122,000	2,086,000	2,376,000	2,222,000	1,956,000
STONE#2	2,090,000	2,533,000	553,000	0	0	750,000
STONE	3,970,000	4,655,000	2,639,000	2,376,000	2,222,000	2,706,000
BY#1	895,000	1,057,000	1,051,000	1,284,000	1,152,000	1,326,000
L PECOAL	4,865,000	5,712,000	3,690,000	3,660,000	3,374,000	4,032,000
FOR SCRUBBER						
STONE#1	256,000	290,000	282,000	317,000	108,000	0
STONE#2	281,000	342,000	75,000	0	0	0
L GAS	537,000	632,000	357,000	317,000	108,000	0
OIL, TOTAL COAL & TOTAL GAS						
STEAM	13,828,000	14,410,000	12,274,000	10,905,000	11,890,000	14,681,000

. (NO.6 & NO. 2)	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
UYLKILL#1	2,173,000	1,181,000	1,032,000	689,000	463,000	687,000	11,730,000
YSTONE1&2	227,000	201,000	202,000	171,000	203,000	232,000	2,339,000
YSTONE3&4	7,895,000	4,864,000	1,946,000	2,538,000	2,484,000	3,653,000	51,753,000
Y 1,2,3,4	8,122,000	5,065,000	2,148,000	2,709,000	2,687,000	3,885,000	54,092,000
(SULFUR)	818,000	629,000	677,000	0	0	0	2,772,000
YSTONE	8,940,000	5,694,000	2,825,000	2,709,000	2,687,000	3,885,000	56,864,000
BY#1	7,000	9,000	16,000	10,000	7,000	16,000	141,000
BY#2	2,035,000	641,000	2,066,000	1,501,000	1,203,000	1,757,000	13,507,000
(SULFUR)	246,000	199,000	158,000	80,000	68,000	150,000	1,936,000
BY	2,288,000	849,000	2,240,000	1,591,000	1,278,000	1,923,000	15,584,000
WARE 7&8	2,797,000	2,027,000	1,245,000	1,049,000	428,000	1,186,000	18,392,000
MOND	0	0	0	0	0	0	0
MARK1&2	0	0	0	0	0	0	0
L OIL	16,198,000	9,751,000	7,342,000	6,038,000	4,856,000	7,681,000	102,570,000
STONE#1	2,312,000	2,056,000	2,031,000	2,200,000	2,087,000	1,921,000	25,249,000
STONE#2	2,751,000	1,845,000	2,518,000	2,407,000	2,475,000	1,870,000	19,792,000
STONE	5,063,000	3,901,000	4,549,000	4,607,000	4,562,000	3,791,000	45,041,000
BY#1	1,540,000	1,246,000	1,010,000	528,000	454,000	986,000	12,529,000
L PECOAL	6,603,000	5,147,000	5,559,000	5,135,000	5,016,000	4,777,000	57,570,000
FOR SCRUBBER							
STONE#1	0	0	18,000	286,000	268,000	247,000	2,072,000
STONE#2	0	0	23,000	310,000	318,000	238,000	1,587,000
. GAS	0	0	41,000	596,000	586,000	485,000	3,659,000
OIL, TOTAL COAL & TOTAL GAS							
STEAM	22,801,000	14,898,000	12,942,000	11,769,000	10,458,000	12,943,000	163,799,000

L COST 2 OF 4

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
EMOUTH (PE SHARE)						
STN1 COAL	1,348,000	1,361,000	1,196,000	1,404,000	1,208,000	1,160,000
STN2 COAL	1,213,000	1,054,000	1,112,000	1,225,000	1,094,000	1,155,000
STONE C	2,561,000	2,415,000	2,308,000	2,629,000	2,302,000	2,315,000
ST1&2 OIL	0	17,000	16,000	0	9,000	43,000
STONE	2,561,000	2,432,000	2,324,000	2,629,000	2,311,000	2,358,000
1 COAL	1,260,000	1,491,000	1,352,000	1,357,000	1,249,000	1,345,000
2 COAL	1,374,000	1,342,000	1,485,000	1,460,000	1,230,000	1,166,000
EMAUGH C	2,634,000	2,833,000	2,837,000	2,817,000	2,479,000	2,511,000
1&2 OIL	7,000	7,000	7,000	14,000	14,000	28,000
EMAUGH	2,641,000	2,840,000	2,844,000	2,831,000	2,493,000	2,539,000
EMOUTH	5,202,000	5,272,000	5,168,000	5,460,000	4,804,000	4,897,000
LEAR (PE SHARE)						
NUCLEAR	1,786,023	1,946,704	1,748,943	1,495,563	2,008,504	1,439,942
NUCLEAR	1,739,358	2,065,905	1,566,089	1,426,140	1,006,295	2,019,255
&3INTREST	813,118	786,265	759,413	732,559	705,706	678,854
ATOMIC	4,338,499	4,798,874	4,074,445	3,654,262	3,720,505	4,138,051
BOILER	28,778	28,778	27,900	29,698	28,740	29,698
DIESEL	4,494	4,494	4,352	4,552	4,404	4,552
EM 1	2,086,000	1,953,000	1,795,000	1,831,000	2,033,000	1,831,000
EM 2	1,976,000	1,703,000	848,000	0	0	152,000
1INTEREST	481,915	466,511	451,107	435,703	420,299	404,895
2INTEREST	257,184	246,549	235,913	235,913	235,913	508,291
EM AUXBLR	0	0	0	0	0	0
EM DIESEL	200	200	200	200	200	200
NUCLEAR	5,228,000	4,961,000	4,028,000	5,077,000	4,312,000	4,462,000
NUCLEAR	0	0	0	0	0	0
NUC TOTAL	5,228,000	4,961,000	4,028,000	5,077,000	4,312,000	4,462,000
AUXBOILER	43,749	43,749	42,368	44,299	42,869	44,299
DIESEL	7,122	7,122	6,897	7,211	6,979	7,211
LEAR	14,451,941	14,213,277	11,514,182	11,319,838	10,804,909	11,582,197
E: FOR JIM MILLER						
EM JC2	0	0	0	0	0	0
ER (PRECOMMERCIAL)						
ER	0	0	0	0	0	0

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
EMOUTH (PE SHARE)							
STN1 COAL	1,208,000	1,177,000	1,449,000	271,000	1,112,000	1,333,000	14,227,000
STN2 COAL	1,057,000	1,056,000	1,227,000	1,210,000	1,408,000	1,214,000	14,025,000
STONE C	2,265,000	2,233,000	2,676,000	1,481,000	2,520,000	2,547,000	28,252,000
ST1&2 OIL	27,000	18,000	0	0	18,000	0	148,000
STONE	2,292,000	2,251,000	2,676,000	1,481,000	2,538,000	2,547,000	28,400,000
COAL	1,543,000	1,323,000	1,498,000	1,415,000	1,657,000	1,409,000	16,899,000
COAL	1,478,000	996,000	102,000	1,357,000	1,653,000	1,252,000	14,895,000
HAUGH C	3,021,000	2,319,000	1,600,000	2,772,000	3,310,000	2,661,000	31,794,000
&2 OIL	16,000	8,000	7,000	7,000	0	22,000	137,000
HAUGH	3,037,000	2,327,000	1,607,000	2,779,000	3,310,000	2,683,000	31,931,000
HOUTH	5,329,000	4,578,000	4,283,000	4,260,000	5,848,000	5,230,000	60,331,000
EAR (PE SHARE)							
NUCLEAR	1,915,803	98,880	0	0	1,798,577	1,999,138	16,238,077
NUCLEAR	1,965,941	1,732,694	1,802,039	1,875,236	1,192,160	0	18,391,112
SINTREST	664,921	650,987	969,237	937,582	919,860	902,138	9,520,640
TOMIC	4,546,665	2,482,561	2,771,276	2,812,818	3,910,597	2,901,276	44,149,829
BOILER	31,138	28,124	30,898	29,302	30,278	29,346	352,678
IESEL	4,920	4,444	4,902	4,698	4,856	4,702	55,370
1	1,946,000	1,906,000	2,095,000	2,081,000	2,223,000	2,129,000	23,909,000
2	1,805,000	1,481,000	1,468,000	1,947,000	1,487,000	2,142,000	15,009,000
NTEREST	389,491	374,087	358,683	343,279	327,876	312,472	4,766,318
NTEREST	491,860	475,430	458,999	442,568	426,138	409,707	4,424,465
AUXBLR	0	0	0	0	0	0	0
DIESEL	200	200	200	200	200	200	2,400
UCLEAR	4,428,000	3,842,000	4,403,000	0	0	0	40,741,000
UCLEAR	0	0	0	0	0	0	0
C TOTAL	4,428,000	3,842,000	4,403,000	0	0	0	40,741,000
XBOILER	47,888	43,254	47,713	45,736	47,260	45,770	538,954
IESEL	7,796	7,041	7,767	7,445	7,694	7,451	87,736
AR	13,698,958	10,644,141	11,646,438	7,714,046	8,464,899	7,981,924	134,036,750
FOR JIM MILLER							
JC2	0	0	0	0	0	0	0
(PRECOMMERCIAL)	0	0	0	0	0	0	0

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
ESELS						
OMDY D 1&2	1,400	0	0	0	5,800	2,500
LAWARE D	1,400	1,400	0	1,100	2,500	0
UTHWARK D	0	0	0	0	0	0
HUYLKILL D	0	0	1,400	400	0	0
YSTONE D	800	1,400	1,000	0	200	0
NEMAUGH D	400	1,000	1,000	0	0	0
ESEL	4,000	3,800	3,400	1,500	8,500	2,500
S TURBINES						
UTHWARK CT	17,000	69,000	31,000	0	0	0
OYSTONE CT	23,000	72,000	29,000	0	0	0
LAWARE CT	23,000	67,000	32,000	0	0	0
HUYLKILLCT	9,000	38,000	8,000	0	0	0
ESTER CT	17,000	50,000	23,000	0	0	0
LLS CT	29,000	63,000	29,000	0	0	0
SER CT	20,000	68,000	26,000	0	0	0
Y MTG CT	0	0	0	0	0	0
CH GE CT	185,000	412,000	150,000	72,000	120,000	0
CH NE CT	0	0	0	0	0	0
CH WO CT	0	0	0	0	0	0
CHMOND CT	185,000	412,000	150,000	72,000	120,000	0
OYDON	798,000	1,321,000	632,000	402,000	365,000	260,000
LEH CT	3,000	5,000	3,000	0	0	0
S TURBINES	1,124,000	2,165,000	963,000	474,000	485,000	260,000
TAL IC	1,128,000	2,168,800	966,400	475,500	493,500	262,500

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
D 1&2	0	4,000	800	0	0	0	14,500
E D	11,300	2,700	0	3,800	0	0	24,200
RK D	0	0	0	0	0	0	0
ILL D	2,700	0	0	0	0	0	4,500
E D	0	0	0	600	0	0	4,000
GH D	0	0	0	600	0	0	3,000
	14,000	6,700	800	5,000	0	0	50,200
BINES							
RK CT	0	0	0	11,000	0	0	128,000
NE CT	0	0	0	14,000	0	0	136,000
E CT	0	0	0	29,000	0	0	151,000
ILLCT	0	0	0	3,000	0	0	58,000
CT	0	0	0	17,000	0	0	107,000
T	0	0	0	19,000	0	0	140,000
T	0	0	0	19,000	0	0	133,000
CT	0	0	0	0	0	0	0
CT	64,000	21,000	0	204,000	17,000	66,000	1,311,000
CT	0	0	0	0	0	0	0
CT	0	0	0	0	0	0	0
D CT	64,000	21,000	0	204,000	17,000	66,000	1,311,000
	723,000	780,000	169,000	537,000	131,000	226,000	6,344,000
T	0	0	0	2,000	0	0	13,000
BINES	787,000	801,000	169,000	855,000	148,000	292,000	8,523,000
C	801,000	807,700	169,800	860,000	148,000	292,000	8,573,200

COST 4 OF 4 (SUMMARY)

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
OIL	8,426,000	8,066,000	8,227,000	6,928,000	8,408,000	10,649,000
PECOAL	4,865,000	5,712,000	3,690,000	3,660,000	3,374,000	4,032,000
GAS	537,000	632,000	357,000	317,000	108,000	0
OUTH	5,202,000	5,272,000	5,168,000	5,460,000	4,804,000	4,897,000
IC	1,128,000	2,168,800	966,400	475,500	493,500	262,500
AR	14,451,941	14,213,277	11,514,182	11,319,838	10,804,909	11,582,197
	0	0	0	0	0	0
NTCH	1,378,000	23,000	5,676,000	4,037,000	3,845,000	5,447,000
OHER	18,196	88,196	97,196	143,196	308,196	647,196
Y TRANS	5,225,000	5,295,000	5,261,000	5,891,000	5,921,000	6,394,000
ACT CAP	0	0	0	0	0	0
HANDL'G	839,735	831,978	812,520	816,886	810,367	810,703
COAL, GAS, MINEMOUTH AND IC FOSSIL	20,158,000	21,850,800	18,408,400	16,840,500	17,187,500	19,840,500
L AND NUCLEAR FUEL	34,609,941	36,064,077	29,922,582	28,160,338	27,992,409	31,422,697
CHANGE AND PURCHASE & PUR	6,621,196	5,406,196	11,034,196	10,071,196	10,074,196	12,488,196
L, NUCLEAR, INTERCHANGE, PURCHASE AND OTHER ENERGY	41,231,137	41,470,273	40,956,778	38,231,534	38,066,605	43,910,893
ENERGY AND CONTRCT CAPACITY T	41,231,137	41,470,273	40,956,778	38,231,534	38,066,605	43,910,893
Y, CONTRACT CAPACITY AND FUEL HANDLING TOTAL	42,070,872	42,302,251	41,769,298	39,048,420	38,876,972	44,721,596

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
. OIL	16,198,000	9,751,000	7,342,000	6,038,000	4,856,000	7,681,000	102,570,000
. PECOAL	6,603,000	5,147,000	5,559,000	5,135,000	5,016,000	4,777,000	57,570,000
. GAS	0	0	41,000	596,000	586,000	485,000	3,659,000
OUTH	5,329,000	4,578,000	4,283,000	4,260,000	5,848,000	5,230,000	60,331,000
. IC	801,000	807,700	169,800	860,000	148,000	292,000	8,573,200
AR	13,698,958	10,644,141	11,646,438	7,714,046	8,464,899	7,981,924	134,036,750
	0	0	0	0	0	0	0
NTCH	(12,675,000)	4,921,000	1,760,000	11,493,000	10,977,000	23,511,000	60,393,000
OWER	1,007,280	657,280	435,280	174,280	61,280	79,280	3,716,856
Y TRANS	5,852,000	5,199,000	5,392,000	4,939,000	4,471,000	4,558,000	64,398,000
ACT CAP	0	0	0	0	0	0	0
HANDL'G	0	0	0	0	0	0	4,922,189
OAL, GAS, MINEMOUTH AND IC FOSSIL	28,931,000	20,283,700	17,394,800	16,889,000	16,454,000	18,465,000	232,703,200
AND NUCLEAR FUEL	42,629,958	30,927,841	29,041,238	24,603,046	24,918,899	26,446,924	366,739,950
HANGE AND PURCHASE R PUR	(5,815,720)	10,777,280	7,587,280	16,606,280	15,509,280	28,148,280	128,507,856
NUCLEAR, INTERCHANGE, PURCHASE AND OTHER NERGY	36,814,238	41,705,121	36,628,518	41,209,326	40,428,179	54,595,204	495,247,806
NERGY AND CONTRCT CAPACITY	36,814,238	41,705,121	36,628,518	41,209,326	40,428,179	54,595,204	495,247,806
CONTRACT CAPACITY AND FUEL HANDLING OTAL	36,814,238	41,705,121	36,628,518	41,209,326	40,428,179	54,595,204	500,169,995

HENT OF OPERATIONS - ELECTRIC PRODUCTION 1 OF 5

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
TING STATISTICS - MWH OUTPUT						
DELPHIA AREA STATIONS						
PE STM.	269,000	316,000	204,000	200,000	185,000	220,000
E STM.	153,000	146,000	146,000	114,000	146,000	186,000
STEAM	422,000	462,000	350,000	314,000	331,000	406,000
OUTH						
NE STA	203,000	192,000	183,000	205,000	179,000	180,000
AUGHSTA	169,000	182,000	182,000	178,000	157,000	159,000
INEMTH	372,000	374,000	365,000	383,000	336,000	339,000
STEAM	794,000	836,000	715,000	697,000	667,000	745,000
R (NOTE: SALEM 2 MWH SOLD TO GPU INCLUDED).						
BOT#2	258,117	281,339	252,759	216,140	290,270	208,102
BOT#3	229,561	272,658	206,693	188,222	132,811	266,502
1	282,000	264,000	242,000	247,000	274,000	247,000
#2	317,000	273,000	136,000	0	0	21,000
ICK #1	663,000	629,000	511,000	643,000	546,000	565,000
ICK #2	0	0	0	0	0	0
CLEAR	1,749,678	1,719,997	1,348,452	1,294,362	1,243,081	1,307,604
AL COMBUSTION						
	60	60	60	30	140	40
URBINE	4,460	11,550	4,520	1,060	1,770	0
N	12,700	21,300	10,400	6,500	5,900	4,200
B.	17,220	32,910	14,980	7,590	7,810	4,240
OSSIL, NUCLEAR & I. C. (NOTE: SALEM 2 MWH SOLD TO GPU INCLUDED).						
EN	2,560,898	2,588,907	2,078,432	1,998,952	1,917,891	2,056,844

Page 20

NT OF OPERATIONS - ELECTRIC PRODUCTION 1 OF 5

NG STATISTICS - MWH OUTPUT

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
LPHIA AREA STATIONS							
STM.	355,000	277,000	296,000	271,000	264,000	251,000	3,108,000
STM.	277,000	156,000	113,000	102,000	78,000	132,000	1,749,000
TEAM	632,000	433,000	409,000	373,000	342,000	383,000	4,857,000
TH							
E STA	174,000	171,000	205,000	113,000	191,000	193,000	2,189,000
GHSTA	188,000	144,000	99,000	170,000	204,000	163,000	1,995,000
NEMTH	362,000	315,000	304,000	283,000	395,000	356,000	4,164,000
STEAM	994,000	748,000	713,000	656,000	737,000	739,000	9,041,000
(NOTE: SALEM 2 MWH SOLD TO GPU INCLUDED).							
OT#2	276,875	14,290	0	0	248,293	275,980	2,322,163
OT#3	259,465	228,681	237,790	246,797	156,899	0	2,426,079
	263,000	257,000	283,000	281,000	300,000	287,000	3,227,000
2	255,000	209,000	207,000	275,000	210,000	302,000	2,205,000
CK #1	561,000	486,000	555,000	0	0	0	5,159,000
CK #2	0	0	0	0	0	0	0
LEAR	1,615,338	1,194,971	1,282,790	802,797	915,192	864,980	15,339,242
. COMBUSTION							
	210	100	10	80	0	0	790
BINE	860	280	0	4,100	240	930	29,770
	10,700	12,000	2,600	8,100	2,000	3,300	99,700
.	11,770	12,380	2,610	12,280	2,240	4,230	130,260
SSIL, NUCLEAR & I. C. (NOTE: SALEM 2 MWH SOLD TO GPU INCLUDED).							
N	2,621,108	1,955,351	1,998,400	1,471,077	1,654,432	1,608,210	24,510,502

ENT OF OPERATIONS - ELECTRIC PRODUCTION 2 OF 5

	JULY 1986	AUGUST 1986	SEPTEMBER 1986	OCTOBER 1986	NOVEMBER 1986	DECEMBER 1986
ING STATISTICS - MWH OUTPUT (CONTINUED)						
HANGE & PURCHASE						
HANGE POWER						
ED PJM	234,000	213,000	301,000	182,000	295,000	294,000
D PJM	(128,000)	(174,000)	(95,000)	(80,000)	(104,000)	(98,000)
TCH	106,000	39,000	206,000	102,000	191,000	196,000
SED POWER						
NER	516	2,516	2,716	3,916	8,516	16,516
RTY TRANSACTIONS						
Y PWR	173,000	175,000	174,000	191,000	192,000	208,000
NDS'N	0	0	0	0	0	0
INTERCHANGE & PURCHASE						
& PUR	279,516	216,516	382,716	296,916	391,516	420,516
RIVER FLOW GENERATION						
NGO	79,000	57,000	52,000	85,000	123,000	181,000
TORAGE GENERATION						
RUN	143,000	112,000	114,000	95,000	81,000	106,000
TORAGE INPUT						
PUT	(198,000)	(176,000)	(165,000)	(131,000)	(128,000)	(143,000)
ORO	24,000	(7,000)	1,000	49,000	76,000	144,000
PRODUCTION (PRECOMMERCIAL)						
	0	0	0	0	0	0
SALEM 2 MWH SOLD TO GPU INCLUDED IN TOTAL OUTPUT)						
OUTPUT	2,864,414	2,798,423	2,462,148	2,344,868	2,385,407	2,621,360
	2,558,600	2,601,100	2,543,900	2,240,700	2,139,800	2,441,700
Y USE	2,723	2,635	2,926	2,323	3,324	4,231
SALEM 2 MWH SOLD TO GPU EXCLUDED IN "LOSS" CALCULATIONS)						
	303,091	194,688	(84,678)	101,845	242,283	175,429
OUTPUT	10.58	6.96	(3.44)	4.34	10.16	6.69

ENT OF OPERATIONS - ELECTRIC PRODUCTION 2 OF 5

	JANUARY 1987	FEBRUARY 1987	MARCH 1987	APRIL 1987	MAY 1987	JUNE 1987	TOTAL
ING STATISTICS - MWH OUTPUT (CONTINUED)							
HANGE & PURCHASE							
HANGE POWER							
ED PJM	136,000	282,000	259,000	418,000	387,000	725,000	3,726,000
D PJM	(336,000)	(113,000)	(148,000)	(14,000)	(23,000)	(4,000)	(1,317,000)
TCH	(200,000)	169,000	111,000	404,000	364,000	721,000	2,409,000
SED POWER							
NER	22,216	15,616	12,116	5,116	1,916	2,316	93,992
RTY TRANSACTIONS							
PWR	187,000	166,000	172,000	156,000	141,000	144,000	2,079,000
NDS'N	0	0	0	0	0	0	0
INTERCHANGE & PURCHASE							
PUR	9,216	350,616	295,116	565,116	506,916	867,316	4,581,992
IVER FLOW GENERATION							
GO	138,000	172,000	259,000	258,000	205,000	123,000	1,732,000
ORAGE GENERATION							
UN	90,000	91,000	96,000	81,000	80,000	116,000	1,205,000
DRAGE INPUT							
UT	(129,000)	(132,000)	(142,000)	(114,000)	(125,000)	(160,000)	(1,743,000)
RO	99,000	131,000	213,000	225,000	160,000	79,000	1,194,000
RODUCTION (PRECOMMERCIAL)	0	0	0	0	0	0	0
SALEM 2 MWH SOLD TO GPU INCLUDED IN TOTAL OUTPUT)							
UTPUT	2,729,324	2,436,967	2,506,516	2,261,193	2,321,348	2,554,526	30,286,494
	2,642,500	2,552,000	2,365,900	2,220,900	2,065,000	2,283,900	28,656,000
USE	4,950	5,153	5,464	4,640	3,423	2,723	44,515
ALEM 2 MWH SOLD TO GPU EXCLUDED IN "LOSS" CALCULATIONS)	81,874	(120,186)	135,152	35,653	252,925	267,903	1,585,979
TPUT	3.00	(4.93)	5.39	1.58	10.90	10.49	5.24

Data Request (1) (ii) (a)

Production Cost Model - Narrative Description

DESCRIPTION OF TWO AREA PRODUCTION COST PROGRAM

INTRODUCTION

This report describes a long range system generation simulation computer program which calculates production costs such as fuel, startup, operation and maintenance for a pool composed of one or two areas over any number of years. Fossil fuel, nuclear, run of river, pondage and pumped hydro units can be individually or jointly owned. A maximum of 490 units may be modeled with pumped storage hydro units counting as two (pumping & generating modes). Maintenance can be scheduled on a pool or individual area basis. Costs are developed on a weekly basis from a chronological sequence of daily load cycles.

The weekly load shape is divided into 84 bi-hourly intervals and each interval is economically dispatched. Each interval on the pool demand is dispatched using incremental cost curves adjusted for penalty factors. Spinning reserve can be checked each interval on a pool or an individual area basis. If two areas are to be analyzed, an interconnection tie limit can be designated. Then the area generation will be adjusted if the interconnection tie flow exceeds the limit. Economy interchange and its cost based on the true split saving are calculated for each interval. Costs are accumulated on an annual basis.

DEMANDS

An annual area megawatt peak demand and weekly, daily, and bi-hourly per unit load shapes are used to develop the bi-hourly megawatt loads of each area.

Weekly Area Peaks

Fifty-four weekly area peak megawatt loads are calculated from the annual area megawatt peak demand and fifty-four weekly values in per-unit of the annual peak demand. Since all weeks must start at 8 a.m. Monday, the calendar must be stretched into the previous or next year.

Daily Area Peaks

The weekly peak area demands are used to calculate daily area peak megawatt demands through the use of typical seasonal weekly load shapes and the seven values in per-unit of the weekly area peak demand.

Bi-Hourly Area Demands

The daily area peak demands for the week are used to calculate bi-hourly area megawatt demands. Typical seasonal average weekday, Saturday and Sunday load shapes consisting of twelve bi-hourly values in per-unit of the daily area peak demands are used.

The bi-hourly pool megawatt demands are determined by summing the individual area bi-hourly loads.

MAINTENANCE SCHEDULING

Up to 125 maintenance cycles may be used. Each of these cycles contains up to six entries. Each entry represents the number of consecutive weeks that maintenance is to be scheduled each year. The last (non zero) entry in any cycle is the signal to repeat this maintenance cycle.

Each existing unit can be assigned a maintenance cycle and a year to start the maintenance. This information is used to determine the number of consecutive weeks the unit is to be put on maintenance in a particular year.

For example, assume a typical maintenance cycle is made up of the following entries: 2 3 1 0 0 0. The first year maintenance begins, a two-week outage is required. The second and third year, a three and one-week outage is required respectively. The fourth year, the cycle is repeated and two weeks of maintenance are required.

When new units are installed, the maintenance cycles are not used in the first year of service. In the second year a special number of maintenance weeks is provided. The first entry in the maintenance cycle assigned to the new unit takes control in the third year of service.

Maintenance can be scheduled on a pool or on an individual area basis. A group of weeks can be designated as non-maintenance weeks for the pool or for each individual area if maintenance scheduling is to be done on that basis.

If desired, particular weeks for particular units can be specified and the manual maintenance option used.

The actual maintenance scheduling is done in the following manner. The capacity of those units to be taken out of service under the manual maintenance option is added to the peak demand of those weeks that the units will be out of service. The generating unit of those remaining having the largest capacity is selected for scheduling first. The available maintenance weeks are searched to find the one with the lowest peak demand plus capacity on planned outage. The generating unit is assigned one week of maintenance for that week. If more than one consecutive week of maintenance is required, the adjacent week with the next lowest peak demand plus generating capacity on planned outage is selected. This process is continued until all weeks of maintenance for this unit are accounted for. The peak megawatt demands of the weeks selected for this unit's maintenance are modified temporarily by added the generating units capacity to them. The next largest unit has its maintenance scheduled on this modified load shape and the process is repeated until all units requiring maintenance are scheduled. This technique insures the proper levelized distribution of maintenance scheduling for all units over the weeks available for maintenance during the year.

FORCED OUTAGE REPRESENTATION

Forced outages are recognized for hydro units by modifying the megawatt values by the factor (1 - forced outage rate). Fossil steam, combustion turbines and nuclear generating units are forced out by a "Monte Carlo" routine. This routine operates as follows: for each available unit a random number is

generated. The random number, having a value between zero and one, is compared to the forced outage rate of the unit. If the random number is equal to or less than the forced outage rate, the unit is considered as forced out for the period selected. The period of time covered by one forced outage can be one bi-hourly interval.

INCREMENTAL COST CURVES

Up to five points (four straight line segments) can be used to represent a thermal unit's power curve. Each year for each thermal unit, the incremental cost vs. megawatt output curve is developed from the fuel cost, minimum heat input and the incremental heat rate vs. megawatt output curve. Then the costs are modified by the unit penalty factor. This modified curve is then entered into an economic schedule point by point.

ECONOMIC SCHEDULE

The economic loading schedule steps can be specified. By default the program will use a schedule covering the range from 2 mills/kwhr to 175 mills/kwhr. For all thermal units, each incremental cost point is compared to each specified schedule value until they match. When this occurs, the associated mw value is stored in the schedule. Totals are accumulated by pool and individual area (owned and internal) generation.

Each week the schedule is modified to account for capacity maintenance outages, additions and retirements. The schedule is also adjusted for any must run units.

HYDRO DISPATCH

All hydro scheduling is done on a weekly basis on the pool load shape.

Run-of-River

Run-of-river hydro is scheduled first. A maximum of five different seasonal megawatt capacities are allowed for each installation. The appropriate capa-

city for the current week is subtracted from the (bi-hourly) pool load shape.

Pondage

Pondage hydro is scheduled after the run-of-river hydro. A maximum of five different seasonal weekly energies are allowed for each installation. These energies represent the megawatt-hour output for a full week during any season.

Pondage hydro is dispatched in the following manner. The appropriate energy for the current week is divided by five to obtain the maximum available energy per day (based on a five day week). The number of hours of scheduling per day is found by dividing the daily energy by the capacity. If the number of hours of scheduling per day exceeds 18, scheduling will not be done on a five day week, but on a seven day week to prevent generation during the lowest off-peak hours.

Assuming conditions call for seven day scheduling, the number of hours of scheduling per day is calculated as above. If this number exceeds 24 hours per day, the installation is run at full capacity, 24 hours per day, seven days per week.

Whether scheduling on a five or seven day week, peak shaving is done to assure that the largest bi-hourly pool demand of each day are reduced by the capacity of the installation.

Variable generation can be simulated by allowing the user to specify the number of smaller units he wishes to assign to the installation. The capacity of each of these smaller units must equal the installation capacity/number of units. In this case the pool load shape is now peak shaved in several passes (equal to the number of units specified) giving a smoother load shape modification.

Pumped Storage

Pumped storage hydro is scheduled after pondage hydro. It is scheduled in order of decreasing efficiency and if two units have the same efficiency, then

in order of decreasing size.

Pumped storage scheduling is based on developing economic megawatt levels over intervals of time from the pool incremental cost curve developed for the week (Economic Schedule) and the cycle efficiency of the installation. These megawatt levels, the chronological bi-hourly load shape for the week, and the physical constraints of the installation are used to optimize the economic generation and pumping schedule for the week.

The dispatch of the pumped hydro is made on the basis of the following constraints and assumptions:

1. The pond is full at the beginning and end of each week.
2. The influence of variable head will not be considered.
3. It is not economic to use pumped hydro generation unless the ratio of the average incremental cost of the demand to be increased by pumping, to the average incremental cost of the load to be decreased by generation, is less than or equal to the hydro cycle efficiency.

The basic idea shown is that certain economic mw levels exist above which the savings incurred by generation must be greater than or equal to the cost incurred by pumping. If these conditions do not exist, then operation will not occur.

GAS TURBINE DISPATCH

Gas turbines not designated as peak shaving are entered into the economic table for dispatch on an equal incremental cost basis or where they may be started to supply adequate spinning reserve. Peak shaving gas turbines are designated by the user entering the number of hours of daily operation desired. The hours are converted to bi-hourly intervals by dividing by two and rounding to the next highest number. The pool load shape is peak shaved Monday through Friday by subtracting the capacity from the highest intervals.

INTERCONNECTION TIE LINES

After the economic schedule for area and pool generating capacity have been modified for the week and all the hydro and peak shaving gas turbines have been dispatched, each bi-hourly interval is dispatched. The thermal generation equal to the modified bi-hourly pool demand is found in the economic table. This pool generation is composed of the internal generation components of each area if two areas are being studied.

The bi-hourly tie line flow between areas is calculated as the differences between the first area's modified demand and its internal generation.

If a tie limit is specified between areas and the calculated tie flow exceeds it, then the logic will adjust the generation of each area by an amount equal to the difference between the tie flow and the limit.

SPINNING RESERVE

Spinning reserve can be determined bi-hourly on a pool or individual area basis. The spinning reserve requirement is specified in the input data as a percentage of the unmodified pool or individual area loads, a fixed mw valve, or the higher of the previous two.

If the pool option is selected, the process is as follows:

1. If a tie-line limit is not specified, then the difference between the pool thermal capacity associated with the thermal generation found in the economic schedule is the excess capacity on-line. If this excess capacity is enough to cover the spinning percentage (converted to megawatts) then the program goes on to the next interval. If it is not sufficient, then additional units are started to satisfy the spinning reserve requirements.

2. If a tie-line limit is specified and the area generation has been modified to the limit the flow between areas, then the pool thermal capacity is the sum of the individual area on-line capacities associated with the internal generation of each area. If the excess capacity is enough to cover the pool spinning percentage (converted to megawatts), the program continues. If it is not enough, the program schedules additional units.

If the area reserve option is selected, the area megawatt requirements is determined from the bi-hourly area demand and the area percentage spinning reserve required. Each area's internal generation is scheduled to meet the demand. If enough excess capacity does not exist to cover each individual area requirement, the program schedules additional units in that particular area. If an area reserve requirement has not been corrected after all available units have been exhausted, then the generation in each area will be adjusted within the tie line limits.

COSTS

The fuel cost associated with the megawatt-hour output of each unit is calculated bi-hourly. Once all the bi-hourly intervals have been considered for the entire week, the variable operation and maintenance cost based on the weekly megawatt-hour output and the start-up cost based on the number of starts the unit had during the week are calculated.

INTERCHANGE

Bi-hourly interchange energy between areas is calculated as the difference between the first area's demand and its owned component of the pool generation.

The cost of the interchange energy is determined in the following manner:

1. The 'incremental' cost of the interchange energy supplied by the export area is determined.

2. The incremental cost of the interchange energy if it was supplied by the import area is determined.
3. The savings resulting from coordinated economic dispatch is the cost difference between items 1 and 2 above times the energy.
4. The cost of the interchange to the import company is equal to the cost the export area incurred supplying the energy (item 1 x energy) plus one-half the savings (item 3).

SEASONAL FUEL COST FACTORS

Fuel costs for any one unit may be changed a maximum of four times a year. For each unit, four(4) beginning week numbers and seasonal fuel cost factors associated with each week number may be specified.

The fuel cost used by the program will equal the original input fuel cost times the annual fuel escalation times the seasonal fuel cost factor in effect.

ADDENDUM TO"DESCRIPTION OF PRODUCTION COST PROGRAM"

The PECO production cost computer program has been modified so that three dispatching areas can be modeled. A maximum of 41 companies/entities within these three areas may be represented individually. Each one requires a bi-hourly load model as described above.

Transmission limitations among areas are defined by a polygon shaped curve. The areas' economic dispatch is adjusted so that their interchange levels fall within this transmission limitation curve.

Data Request (1) (ii) (b)

Production Cost Model Input Data

INPUT DATA CARD EXPLANATIONS

#5 CARD - ANNUAL FOSSIL FUEL ESCALATION CURVES

These numbers are multiplied by the input base fuel prices on the unit data cards.

Column 12 - Fuel Type Number
1 = Coal
2 = #6 Oil (1%)
3 = #2 Oil
4 = Gas
5 = #6 Oil (.5%)

Column 14-72 - Annual factors used to multiply base fuel prices by the first number is 1985 and the last is 1995.

#9 CARD - DAILY LOAD SHAPE

There is one card for each month and each card represents the typical week of that month (Monday - Sunday)

Column 1- 2 - Week Number
Column 3- 8 - Monday Factor
Column 9-14 - Tuesday Factor
Column 15-20 - Wednesday Factor
Column 21-26 - Thursday Factor
Column 27-32 - Friday Factor
Column 33-38 - Saturday Factor
Column 39-44 - Sunday Factor
Column 45-80 - Not Used By Program - Comments Only

#10 CARD - BI-HOURLY LOAD SHAPE

There are three cards for each month. The first card represents a typical weekday, the second card shows a typical Saturday and the third card is a typical Sunday. The days begin at 8:00 AM.

Column 1- 2 - Week Number
Column 3-74 - Bi-Hourly Factors

#12 CARD - SEASONAL FUEL COST FACTOR

Factor to reflect seasonal price changes of fossil fuels. This number is multiplied by the annual escalation factor and the fuel price on the unit data card to obtain the projected fuel price.

Column 13-14 - Fossil Fuel Type
1 = Coal
2 = #6 Oil (1%)
3 = #2 Oil
4 = Gas
5 = #6 Oil (.5)

Column 16-17 - Week Number
Column 19-23 - Factor (Winter)
Column 25-26 - Week Number
Column 28-32 - Factor (Spring)
Column 34-35 - Week Number

Column 37-41 - Factor (Summer)
Column 43-44 - Week Number
Column 46-50 - Factor (Fall)
Column 52-80 - Fuel Type (Comment - Not Used By Program)

#13 CARD - UNIT DATA CARDS

These cards supply the basic data input for each of the units.

1st Card

Column 4-11 - Unit Name
Column 16 - Type Of Unit
1 = Fossil Steam - Oil
2 = Run Of River Hydro
3 = Pondage Hydro
4 = Pumped Storage Hydro
5 = Nuclear
6 = Internal Combustion
7 = Fossil Steam - Coal
Column 17-18 - For CT's - Number of hours during the Monday - Friday period that the unit must run. For all others number of years that the unit is must run.
Column 19-20 - Week number that unit goes into service (for new units only)
Column 21-26 - Net capacity of the unit.
Column 30 - Interconnection Accounting selector switch = 1 - normal unit.
Column 3 - Maintenance cycle number.
Column 34-38 - Maintenance cycle starting year.
Column 39-40 - Number of weeks of maintenance during the first year after installation.
Column 41-45 - Immature forced outage rate for new units. The program decreases this number over five years until it reaches the mature forced outage rate.
Column 46-50 - Mature forced outage rate for all years.
Column 51-55 - Transmission penalty factor adjustment to model transmission losses.
Column 56-60 - Fuel cost - ($/MBTU).
Column 61-65 - Minimum load heat requirement total heat (MBTU) at the first incremental MW level.
Column 71-75 - Variable O&M cost ($/MWH) represents an estimate of the maintenance cost in proportion to the generation. This is used only for ordering the units for dispatching purposes only.
Column 76-77 - Fuel accumulation number - references type of fuel used.
Column 78-79 - Company abbreviation.

Column 80 - Joint-Owned Switch
- J = Joint Owned Unit - If this is used, then the next card is the percentages owned by each company.

2nd Card

Column 4 - Third Card Switch blank
no third unit data card
=1 third unit data card

Column 5- 8 - First year to begin of fuel esculation for nuclear units - year of installation (not used).

Column 10-12 - Escalation curve number applies to the curve numbers on the annual and seasonal curves.

Column 14-18 - Net MW at a point on the unit's incremental energy curve.

Column 19-23 - Incremental heat rate at the same point on the energy curve.

Column 25-29, 30-34}
36-40, 41-45} Repeat of Column 14-18, 19-23
47-51, 52-56}
58-62, 63-67}

Column 72 - Variable O&M escalation curve number provided on #41 card

3rd Card

Column 4- 8 - Maintenance Outage Rate
Added to forced outage rate at night and on weekends.

Column 9-13 - Hot Start Curve Number
Selects a cool-down rate curve.

Column 14-18 - Immature outage year.
Year to start immature forced outage rate if different than the installation year.

Column 19-23 - Daytime Outage Rate
Added to forced outage rate during daytime hours.

Column 24-25 - Minimum number of bi-hours that the unit must run if started.
Default - 3 bi-hours - steam
24 bi-hours - nuclear
0 bi-hours - IC

#16 CARD ANNUAL PEAKS

This number is multiplied by the factor on the 9, 10 and 21 cards to obtain the bi-hourly load.

Column 1- 2 - Company abbreviation
Column 6- 9 - Company projected peak.

#21 CARD - MONTHLY AND WEEKLY LOAD SHAPE

The first two cards represent the typical month and the next six cards are the factors to model the typical week.

1st 2 Cards

Column 12-52 - Monthly Factors

Next 6 Cards

Column 12-73 - Weekly Factors

#24 CARD - NUCLEAR SEASONAL FUEL FACTOR

Fuel cost for nuclear units in $/MBTU multiplied by fuel cost on unit data cards, which is set to 1.00 for all nuclear units.

Column 4-11 - Unit Name.
Column 16-17 - Week Number - Week 1 unless the unit is an addition during year.
Column 19-23 - Fuel Price ($/MBTU)
Column 25-26 - Week Number - For a price change during the year.
Column 29-32 - New Fuel Price ($/MBTU)

#28 CARD - PERFORMANCE FACTOR

This card is used for a performance factor or as a factor to re-rate the capacity to allow for seasonal changes due to ambient conditions.

Column 4-11 - Unit Name.
Column 13 - Negative or blank.
Blank - Factor is to be used as a performance factor.
Negative - Re-ration factor for the capacity shown in the unit data cards.
Column 14 - Week Number.
Column 15-19 - Performance factor or re-ration factor.
Columns 20-27, 28-35, 36-43, 44-51 - Repeat of Columns 13-19

#41 CARD - VARIABLE O&M ESCALATION CURVES

These numbers are multiplied by the input variable O&M costs on the unit data cards.

Column 12 - Escalation Curve Number.
Columns 14-72 - Annual factors used to multiply base variable O&M numbers by. The first number is for 1985.

Sheet 5

```
START
 COL  ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8
  2  5     FOSSIL FUEL ESCULATION CURVES
 12           1 1.000 1.000 1.134 1.230 1.326 1.389 1.500 1.620 1.750 1.890 COAL
 14             2.041
 12           2 1.000 1.000 1.383 1.561 1.700 1.624 1.770 1.930 2.103 2.293 HEAVY
 14             2.499                                                       1% SULF
 12           3 1.000 1.000 1.252 1.428 1.577 1.509 1.645 1.793 1.954 2.130 LIGHT
 14             2.322
 12           4 1.000 1.000 1.383 1.561 1.700 1.444 1.585 1.740 1.910 2.096 GAS
 14             2.300
 12           5 1.000 1.000 1.436 1.621 1.765 1.685 1.836 2.002 2.182 2.378 HEAVY
 14             2.592                                                       .5 & .3%
 12           6 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000
 14             1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000 1.000
 12           7 1.070 1.140 1.210 1.280 1.350 1.420 1.490 1.560 1.630 1.700
 14             1.770 1.840 1.910 1.980 2.050 2.120 2.190 2.260 2.330 2.400
  1 999
  1 41     VOM ESCULATION CURVES
 12           1 1.000 1.045 1.097 1.163 1.233 1.307 1.385 1.468 1.556 1.649
 14             1.748 1.853 1.964 2.082 2.207 2.339 2.479 2.628 2.786
 12           2 1.000 1.045 1.097 1.163 1.233 1.307 1.385 1.468 1.556 1.649
 14             1.748 1.853 1.964 2.082 2.207 2.339 2.479 2.628 2.786
 12           3 1.000 1.045 1.097 1.163 1.233 1.307 1.385 1.468 1.556 1.649
 14             1.748 1.853 1.964 2.082 2.207 2.339 2.479 2.628 2.786
 12           4 1.000 1.045 1.097 1.163 1.233 1.307 1.385 1.468 1.556 1.649
 14             1.748 1.853 1.964 2.082 2.207 2.339 2.479 2.628 2.786
 12           5 1.000 1.045 1.097 1.163 1.233 1.307 1.385 1.468 1.556 1.649
 14             1.748 1.853 1.964 2.082 2.207 2.339 2.479 2.628 2.786
 12           6 1.000 1.045 1.097 1.163 1.233 1.307 1.385 1.468 1.556 1.649
 14             1.748 1.853 1.964 2.082 2.207 2.339 2.479 2.628 2.786
 12           7 1.000 1.045 1.097 1.163 1.233 1.307 1.385 1.468 1.556 1.649
 14             1.748 1.853 1.964 2.082 2.207 2.339 2.479 2.628 2.786
  1 999
  1 13       EXISTING  UNIT DATA
  4    PCHBOT2     5   1  1051   1                .16   1.   1.000 7853      2.0525PLJ
  1 PS4249PE4249AE0751DP0751
  5      1974       700  900  1051 1100                                      1
  4    PCHBOT3     5   1  1035   1                .16   1.   1.000 7853      2.0625PLJ
  1 PS4249PE4249AE0751DP0751
  5      1975       700  900  1035 1100                                      1
  4    SALEM1      5      1071   1                .180 1.04  1.000 5385      5.93 IPSJ
  1 PS4259PE4259AE0741DP0741
  5      1977       455  939   900  956   968  980  1071  985               1
  4    SALEM2      5      1095   1                .180 1.04  1.000 5385      4.18 IPSJ
  1 PS4259PE4259AE0741DP0741JC0000
  5      1982       455  939   900  956   968  980  1095  986               1
  4    LIMERCK1    5  08  1055   1 56      .25  .16   1.  1.000 7853        2.0539PE
  5      1985       700  900  1055 1100                                      1
  4    CROMBY1     7      150   1                .120 1.0111.632  477       11.2023PE
  4    11985  1    42  914    80  951   130  973   150 1037                  1
 13           2
  4    CROMBY2     1      211   1                .188 1.03 3.705  409       2.8021PE
  4    11985  2    34  883   105  891   172  922   211  943                  2
 13           2
  4    DELAWRE7    1      127   1                .193 1.00 3.706  255       5.3121PE
```

Sheet 6

```
START
 COL ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8
  4    11985  5    22  941   115  950   127 1005                              5
 13          2          2
  4    DELAWRE8    1       130   1                .282 1.00 3.706  256       5.9021PE
  4    11985  5    22  957   101  959   130  992                              5
 13          2          2
  4    EDDYSTN1    730     270   1                .30  1.0081.798 1448       17.5823PE
  4    11985  1   152  888   259  889   260  957   270  975                   1
 13          2
  4    EDDYSTN2    730 1   270   1  7 1983        .26  1.0051.798 1477       11.6923PE
  4    11985  1   152  887   182  888   183  891   270  893                   1
 13          2
  4    EDDYSTN3    1       376   1                .196 1.0003.706  536       3.7421PE
  4    11985  5    38 1026   247 1038   346 1070   376 1116                   5
 13          2
  4    EDDYSTN4    1       376   1                .164 1.0003.706  536       3.7621PE
  4    11985  5    38 1026   247 1038   346 1070   376 1116                   5
 13          2
  4    RICHMND9    1       177   1                .323  1. 3.706   900       5.8321PE
  4    11985  5    76 1166   165 1197   177 1386                           5
 13          2         -1
  4    SCHUYLL1    1       172   1                .341 .993 3.747  317       5.0921PE
  4    11985  5    26  893    60  904    90  933   172  963                   5
 13          2          5
  4    SCHUYLL3    1       53    1                .03  1.5003.747  254       6.2521PE
  5     1985  5    53  480                                                    5
  4    SOUTHNK1    1       178   1                .456  1. 3.706  355        7.5721PE
  4    11985  5    20 1110    61 1238   125 1415   178 1632                   5
 13          2
  4    SOUTHNK2    1       178   1                .308  1. 3.706  389        7.8221PE
  4    11985  5    25 1102    66 1340   134 1497   178 1702                   5
 13          2
  4    DELAPH09    6       18    1 44 1985        .114  1.0 5.522  246       7.88426PE
  4    11985  3    18 1367                                                    3
 13          1
  4    DELAPH10    6       16    1 44 1985        .061  1.0 5.522  223       8.79226PE
  4    11985  3    16 1392                                                    3
 13          1
  4    DELAPH11    6       16    1 44 1985        .122  1.0 5.522  223       8.79226PE
  4    11985  3    16 1392                                                    3
 13          1
  4    DELAPH12    6       16    1 44 1985        .256  1.0 5.522  223       8.79226PE
  4    11985  3    16 1392                                                    3
 13          1
  4    EDDYPH10    6       16    1 44 1985        .048  1.0 5.523  223       8.79226PE
  4    11985  3    16 1392                                                    3
 13          1
  4    EDDYPH20    6       16    1 44 1985        .118  1.0 5.523  223       8.79226PE
  4    11985  3    16 1392                                                    3
 13          1
  4    EDDYPH30    6       16    1 44 1985        .058  1.0 5.523  227       8.80626PE
  4    11985  3    16 1419                                                    3
 13          1
  4    EDDYPH40    6       16    1 44 1985        .027  1.0 5.523  227       8.80626PE
  4    11985  3    16 1419                                                    3
```

UNITS

Sheet 7

```
START
 COL ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8
  13                1
   4  MOSERPM1    6                 18   1 44 1985      .053  1.0 5.579  246     7.88426PE
   4  11985  3    18 1367                                                          3
  13                1
   4  MOSERPM2    6                 18   1 44 1985      .076  1.0 5.579  246     7.88426PE
   4  11985  3    18 1367                                                          3
  13                1
   4  MOSERPM3    6                 18   1 44 1985      .035  1.0 5.579  246     7.88426PE
   4  11985  3    18 1367                                                          3
  13                1
   4  CROYGE11    6                 48   1 44 1985      .235  1.0 5.373  562     4.55526PE
   4  11985  3    48 1170                                                          3
  13                1
   4  CROYGE12    6                 48   1 44 1985      .196  1.0 5.373  562     4.55526PE
   4  11985  3    48 1170                                                          3
  13                1
   4  CROYGE21    6                 54   1 44 1985      .284  1.0 5.373  565     4.05126PE
   4  11985  3    54 1046                                                          3
  13                1
   4  CROYGE22    6                 43   1 44 1985      .454  1.0 5.373  524     5.06626PE
   4  11985  3    43 1219                                                          3
  13                1
   4  CROYGE31    6                 48   1 44 1985      .223  1.0 5.373  562     4.55526PE
   4  11985  3    48 1170                                                          3
  13                1
   4  CROYGE32    6                 54   1 44 1985      .171  1.0 5.373  565     4.05126PE
   4  11985  3    54 1046                                                          3
  13                1
   4  CROYGE41    6                 48   1 44 1985      .294  1.0 5.373  562     4.55526PE
   4  11985  3    48 1170                                                          3
  13                1
   4  CROYGE42    6                 54   1 44 1985      .312  1.0 5.373  565     4.05126PE
   4  11985  3    54 1046                                                          3
  13                1
   4  RICHGE81    6                 59   1 44 1985      .262  1.0 5.364  706     2.80426PE
   4  11985  3    59 1197                                                          3
  13                1
   4  RICHGE91    6                 59   1 44 1985      .112  1.0 5.364  706     2.80426PE
   4  11985  3    59 1197                                                          3
  13                1
   4  RICHGE92    6                 59   1 44 1985      .111  1.0 5.364  706     2.80426PE
   4  11985  3    59 1197                                                          3
   4  .0            1
   4  RICHNE41    6                 26   1 44 1985      .067  1.0 5.364  394     5.18926PE
   4  11985  3    26 1515                                                          3
  13                1
   4  RICHNE42    6                 26   1 44 1985      .325  1.0 5.364  394     5.18926PE
   4  11985  3    26 1515                                                          3
  13                1
   4  RICHNE43    6                 26   1 44 1985      .204  1.0 5.364  394     5.18926PE
   4  11985  3    26 1515                                                          3
  13                1
   4  RICHNE44    6                 26   1 44 1985      .076  1.0 5.364  394     5.18926PE
   4  11985  3    26 1515                                                          3
```

Sheet 8

```
START
 COL ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8
 13                1
  4    RICHNE71    6          26   1 44 1985      .077  1.0 5.364  394     5.18926PE
  4    11985   3    26 1515                                                    3
 13                1
  4    RICHNE72    6          26   1 44 1985      .158  1.0 5.364  394     5.18926PE
  4    11985   3    26 1515                                                    3
 13                1
  4    RICHNE73    6          26   1 44 1985      .079  1.0 5.364  394     5.18926PE
  4    11985   5    26 1515                                                    5
 13                1
  4    RICHNE74    6          26   1 44 1985       1.0  1.0 5.364  394     5.18926PE
  4    11985   3    26 1515                                                    3
 13                1
  4    RICHNO21    6          36   1 44 1985      .122  1.0 5.364  526     7.80126PE
  4    11985   3    36 1460                                                    3
 13                1
  4    RICHNO22    6          36   1 44 1985      .041  1.0 5.364  526     7.80126PE
  4    11985   3    36 1460                                                    3
 13                1
  4    RICHNO31    6          36   1 44 1985      .036  1.0 5.364  526     7.80126PE
  4    11985   3    36 1460                                                    3
 13                1
  4    RICHNO32    6          36   1 44 1985      .156  1.0 5.364  526     7.80126PE
  4    11985   3    36 1460                                                    3
 13                1
  4    RICHNO51    6          36   1 44 1985      .014  1.0 5.364  526     7.80126PE
  4    11985   3    36 1460                                                    3
 13                1
  4    RICHNO52    6          36   1 44 1985      .041  1.0 5.364  526     7.80126PE
  4    11985   3    36 1460                                                    3
 13                1
  4    RICHNO61    6          36   1 44 1985      .041  1.0 5.364  526     7.80126PE
  4    11985   3    36 1460                                                    3
 13                1
  4    RICHNO62    6          36   1 44 1985      .113  1.0 5.364  526     7.80126PE
  4    11985   3    36 1460                                                    3
 13                1
  4    FALLSPH1    6          18   1 44 1985      .034  1.0 5.551  246     7.88426PE
  4    11985   3    18 1367                                                    3
 13                1
  4    FALLSPH2    6          18   1 44 1985      .215  1.0 5.551  246     7.88426PE
  4    11985   3    18 1367                                                    3
 13                1
  4    FALLSPH3    6          18   1 44 1985      .034  1.0 5.551  246     7.88426PE
  4    11985   3    18 1367                                                    3
 13                1
  4    SCHUPH10    6          16   1 44 1985      .134  1.0 5.521  225     8.80126PE
  4    11985   3    16 1408                                                    3
 13                1
  4    SCHUPH11    6          18   1 44 1985      .252  1.0 5.521  244     7.87726PE
  4    11985   3    18 1353                                                    3
 13                1
  4    SOUTHPH3    6          16   1 44 1985      .202  1.0 5.528  223     8.79226PE
  4    11985   3    16 1392                                                    3
```

Sheet 9

```
START
 COL ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8
  13          1
   4    SOUTHPN4    6        16   1 44 1985      .059  1.0 5.528  223     8.79226PE
   4    11985  3    16 1392                                               3
  13          1
   4    SOUTHPN5    6        16   1 44 1985      .039  1.0 5.528  223     8.79226PE
   4    11985  3    16 1392                                               3
  13          1
   4    SOUTHPN6    6        16   1 44 1985      .084  1.0 5.528  223     8.79226PE
   4    11985  3    16 1392                                               3
  13          1
   4    CHESTPN7    6        16   1 44 1985      .051  1.0 5.525  223     8.79226PE
   4    11985  3    16 1392                                               3
  13          1
   4    CHESTPN8    6        16   1 44 1985      .140  1.0 5.525  223     8.79226PE
   4    11985  3    16 1392                                               3
  13          1
   4    CHESTPN9    6        16   1 44 1985      .093  1.0 5.525  223     8.79226PE
   4    11985  3    16 1392                                               3
  13          1
   4    PLYMH009    6        35   1 44 1985      .317  1.0 5.533  515     8.14526PE
   4    11985  3    35 1472                                               3
  13          1
   4    PLYMH015    6        35   1 44 1985      .550  1.0 5.533  515     8.14526PE
   4    11985  3    35 1472                                               3
  13          1
   4    CROMBYD1    6         3   1 44 1985      .99 .26 5.579   31    35.6026PE
   5     1985  3     3 1045                                               3
   4    CROMBYD2    6         3   1 44 1985      .99 .26 5.579   31    35.6026PE
   5     1985  3     3 1045                                               3
   4    DELAWRED    6         3   1 44 1985      .99 .26 5.522   31    35.6026PE
   5     1985  3     3 1045                                               3
   4    SCHYKILD    6         3   1 44 1985      .99 .26 5.521   31    35.6026PE
   5     1985  3     3 1045                                               3
   4    SOUTHNKD    6         3   1 44 1985      .99 .26 5.528   31    35.6026PE
   5     1985  3     3 1045                                               3
   4    CONOX       3       350   1                    1.                  28PE
   6      121280 1042070 2315330 4929610          5
   4    CONOY       3        60   1                    1.                  28PE
   6      110080 10 5190 2310080                  4
   4    CONOZ       3        30   1                    1.                  28PE
   6      1 2130 14 2520 29 1350 48 1740          1
   4    CONON       3        60   1                    1.                  28PE
   6      110080 19 4272                          5
   4    MDYRN182    4       220   1 82 1985      .059  1.                  28PLJ
   1  PE1.00
   7       2775   232  .691  2
   4    MDYRN384    4       220   1 82 1984      .059  1.                  28PLJ
   1  PE1.00
   7       2775   232  .691  2
   4    MDYRN586    4       220   1 82 1985      .059  1.                  28PLJ
   1  PE1.00
   7       2775   232  .691  2
   4    MDYRN788    4       220   1 82 1984      .059  1.                  28PLJ
   1  PE1.00
```

Sheet 10

```
START
 COL  ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8
  7       2775   232  .691  2
  4     CONEMA1     730     800   1                .254   1. 1.516 4374      3.0392PNJ
  1  PS2250PE2072AE0383DP0372PL1010BC1056ME1645JC0129PP0972UG0111
  4     11985   1   500  779   717  799   766  802   800  803                 1
 13           2
  4     CONEMA2     730     800   1                .276   1. 1.516 4374      3.0392PNJ
  1  PS2250PE2072AE0383DP0372PL1010BC1056ME1645JC0129PP0972UG0111
  4     11985   1   500  779   717  799   766  802   800  803                 1
 13           2
  4     KEYSTN1     730     790   1 17 1981        .177   1. 1.220 4381      2.4591PNJ
  1  PS2284PE2099AE0247DP0370PL1095BC2099JC1806PN0000
  4     11985   1   500  756   678  773   790  791                           1
 13           2
  4     KEYSTN2     730     790   1 17 1985        .250   1. 1.220 4381      2.4591PNJ
  1  PS2284PE2099AE0247DP0370PL1095BC2099JC1806PN0000
  4     11985   1   500  756   678  773   790  791                           1
 13           2
  4     CONEMAD     6         8   1 45 1985        .037   1. 5.600   81      26.6192PNJ
  1  PS2250PE2072AE0383DP0372PL1010BC1056ME1645JC0129PP0972UG0111
  5      1985   3     8 1008                                                 3
  4     KEYSTND     6         8   1 45 1985        .083   1. 5.583   82      22.2291PNJ
  1  PS2284PE2099AE0247DP0370PL1095BC2099PN1667JC0139
  5      1985   3     8 1030                                                 3
  4     SALEMCT3    6        29   1 44 1985        .090 1.04 5.362  453      5.517 1PSJ
  1  PS4259PE4259AE0741DP0741
  4     11985   3    29 1563                                                 3
 13           1
  1  999
  1  28          1985 PERFORMANCE FACTORS
  4     SALEM1    11.020
  4     SALEM2    11.022
  4     EDDYSTN1 -1.9955-14.9995-241.012-41.9995-47.9960     CIRC. WATER FACTORS
  4     EDDYSTN2 -1.9927-141.000-241.017-411.000-47.9939     CIRC. WATER FACTORS
  4     EDDYSTN3 -11.003-141.000-24.9998-411.000-471.002     CIRC. WATER FACTORS
  4     EDDYSTN4 -11.003-141.000-24.9998-411.000-471.002     CIRC. WATER FACTORS
  4     CROMBY1  -11.001-141.000-241.011-411.000-471.001     CIRC. WATER FACTORS
  4     CROMBY2  -11.003-141.002-241.027-411.001-471.002     CIRC. WATER FACTORS
  4     DELAWRE7 -1.9970-141.000-241.017-411.000-47.9970     CIRC. WATER FACTORS
  4     DELAWRE8 -1.9964-141.000-241.015-411.000-47.9968     CIRC. WATER FACTORS
  4     SCHUYLL1 -11.000-141.001-241.005-411.001-471.000     CIRC. WATER FACTORS
  4     RICHMND9 -1.9922-141.000-241.022-411.000-47.9926     CIRC. WATER FACTORS
  4     SOUTHNK1 -1.9912-141.000-241.019-411.000-47.9924     CIRC. WATER FACTORS
  4     SOUTHNK2 -1.9912-141.000-241.019-411.000-47.9924     CIRC. WATER FACTORS
  4     EDDYPH10 -11.250-131.000-23.7500-371.000-491.250     MID TEMP BASE
  4     EDDYPH20 -11.250-131.000-23.7500-371.000-491.250     MID TEMP BASE
  4     EDDYPH30 -11.375-131.000-23.8750-371.000-491.375     MID TEMP BASE
  4     EDDYPH40 -11.375-131.000-23.8750-371.000-491.375     MID TEMP BASE
  4     MOSERPH1 -11.222-131.000-23.7778-371.000-491.222     MID TEMP BASE
  4     MOSERPH2 -11.222-131.000-23.7778-371.000-491.222     MID TEMP BASE
  4     MOSERPH3 -11.222-131.000-23.7778-371.000-491.222     MID TEMP BASE
  4     DELAPH09 -11.222-131.000-23.7778-371.000-491.222     MID TEMP BASE
  4     DELAPH10 -11.250-131.000-23.7500-371.000-491.250     MID TEMP BASE
  4     DELAPH11 -11.250-131.000-23.7500-371.000-491.250     MID TEMP BASE
  4     DELAPH12 -11.250-131.000-23.7500-371.000-491.250     MID TEMP BASE
```

Sheet 11

START COL ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8

```
4    SCHUPN10 -11.250-131.000-23.7500-371.000-491.250    MID TEMP BASE
4    SCHUPN11 -11.222-131.000-23.7778-371.000-491.222    MID TEMP BASE
4    CROYGE11 -11.229-131.000-23.7708-371.000-491.229    MID TEMP BASE
4    CROYGE12 -11.229-131.000-23.7708-371.000-491.229    MID TEMP BASE
4    CROYGE21 -11.185-131.002-23.7963-371.000-491.185    MID TEMP BASE
4    CROYGE22 -11.256-131.000-23.7442-371.000-491.256    MID TEMP BASE
4    CROYGE31 -11.229-131.000-23.7708-371.000-491.229    MID TEMP BASE
4    CROYGE32 -11.185-131.000-23.7963-371.000-491.185    MID TEMP BASE
4    CROYGE41 -11.229-131.000-23.7708-371.000-491.229    MID TEMP BASE
4    CROYGE42 -11.185-131.000-23.7963-371.000-491.185    MID TEMP BASE
4    RICHGE81 -11.237-131.000-23.7797-371.000-491.237    MID TEMP BASE
4    RICHGE91 -11.237-131.000-23.7797-371.000-491.237    MID TEMP BASE
4    RICHGE92 -11.237-131.000-23.7797-371.000-491.237    MID TEMP BASE
4    RICHNE41 -11.269-131.000-23.7308-371.000-491.269    MID TEMP BASE
4    RICHNE42 -11.269-131.000-23.7308-371.000-491.269    MID TEMP BASE
4    RICHNE43 -11.269-131.000-23.7308-371.000-491.269    MID TEMP BASE
4    RICHNE44 -11.269-131.000-23.7308-371.000-491.269    MID TEMP BASE
4    RICHNE71 -11.269-131.000-23.7308-371.000-491.269    MID TEMP BASE
4    RICHNE72 -11.269-131.000-23.7308-371.000-491.269    MID TEMP BASE
4    RICHNE73 -11.269-131.000-23.7308-371.000-491.269    MID TEMP BASE
4    RICHNE74 -11.269-131.000-23.7308-371.000-491.269    MID TEMP BASE
4    RICHNO21 -11.194-131.000-23.8056-371.000-491.194    MID TEMP BASE
4    RICHNO22 -11.194-131.000-23.8056-371.000-491.194    MID TEMP BASE
4    RICHNO31 -11.194-131.000-23.8056-371.000-491.194    MID TEMP BASE
4    RICHNO32 -11.194-131.000-23.8056-371.000-491.194    MID TEMP BASE
4    RICHNO51 -11.194-131.000-23.8056-371.000-491.194    MID TEMP BASE
4    RICHNO52 -11.194-131.000-23.8056-371.000-491.194    MID TEMP BASE
4    RICHNO61 -11.194-131.000-23.8056-371.000-491.194    MID TEMP BASE
4    RICHNO62 -11.194-131.000-23.8056-371.000-491.194    MID TEMP BASE
4    FALLSPN1 -11.222-131.000-23.7778-371.000-491.222    MID TEMP BASE
4    FALLSPN2 -11.222-131.000-23.7778-371.000-491.222    MID TEMP BASE
4    FALLSPN3 -11.222-131.000-23.7778-371.000-491.222    MID TEMP BASE
4    SOUTHPN3 -11.250-131.000-23.7500-371.000-491.250    MID TEMP BASE
4    SOUTHPN4 -11.250-131.000-23.7500-371.000-491.250    MID TEMP BASE
4    SOUTHPN5 -11.250-131.000-23.7500-371.000-491.250    MID TEMP BASE
4    SOUTHPN6 -11.250-131.000-23.7500-371.000-491.250    MID TEMP BASE
4    CHESTPN7 -11.250-131.000-23.7500-371.000-491.250    MID TEMP BASE
4    CHESTPN8 -11.250-131.000-23.7500-371.000-491.250    MID TEMP BASE
4    CHESTPN9 -11.250-131.000-23.7500-371.000-491.250    MID TEMP BASE
4    PLYMNO09 -11.229-131.000-23.8000-371.000-491.229    MID TEMP BASE
4    PLYMNO15 -11.229-131.000-23.8000-371.000-491.229    MID TEMP BASE
4    SCHUYLL3 -11.000-14.5000-19.2000-42.5000-471.000    MINTER BASE
1  999
1  16          1986 PEAKS FIRST TIME
1  PE  6160
1  999
1  20
1  20          1986  PE
1  20
1  21  2       1986  6160 PECO
12             0.9984 1.0032 1.0018 0.9984 1.0043 1.0030
12             0.9989 1.0022 0.9958 0.9990 1.0026 0.9998
12             0.7484 0.7565 0.8084 0.7890 0.7744 0.7468 0.7695 0.7516 0.7143
12             0.7240 0.7159 0.7338 0.6834 0.6753 0.6997 0.6786 0.7062 0.6623
```

PROJECT: SO MEMBER: UNITS DATE: 85/12/19 UNITS
GROUP: H LEVEL: 01.01 TIME: 16:13
TYPE: F USERID: T4D6CHB PAGE: 08 OF 09

Sheet 12

```
START
 COL ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8
  12          0.6867 0.6607 0.6997 0.7614 0.7289 0.7500 0.7955 0.8864 0.9221
  12          0.8198 0.9253 1.0000 0.8815 0.9464 0.9545 0.8669 0.7922 0.9091
  12          0.8506 0.7922 0.7256 0.6769 0.6851 0.6575 0.6656 0.6769 0.6948
  12          0.6964 0.7321 0.7159 0.7484 0.7289 0.7727 0.7873 0.7597 0.7679
   1 09 02 1986 PE
   2  10.91910.92760.98931.00000.90520.75900.8317      0.0  0.9427
   2  60.91720.97771.00000.96200.92690.77380.8015      0.0  0.9724
   1 100.96580.96121.00000.94010.90750.75450.8162      0.0  0.9692
   1 140.96000.99201.00000.94840.90320.66890.7832      0.0  0.9407
   1 190.85060.98290.96411.00000.98020.66520.7173      0.0  0.9539
   1 230.81630.99970.95191.00000.90780.73620.6997      0.0  1.0090
   1 270.82710.96900.79611.00000.81090.65470.6876      0.0  0.9494
   1 320.84791.00000.99680.92860.82800.62080.7066      0.0  0.9505
   1 360.83301.00000.92850.86360.80170.59890.7339      0.0  0.9145
   1 400.94400.96851.00000.97360.94100.69930.7792      0.0  0.9610
   1 450.99161.00000.98760.95720.90370.79650.8172      0.0  0.9840
   1 490.91970.91181.00000.99400.88540.80450.8260      0.0  0.9604
   1 999
   1 10 02 1986 PE
   2  10.94660.97140.93120.89880.95890.97020.86860.82250.67030.61650.63040.8143
   2  10.84340.94850.90420.84300.91260.97140.89030.94230.78940.70360.68590.7225
   2  10.77000.85510.87570.85760.92920.97140.93190.84650.73590.67730.69610.9332
   2  60.98160.99320.95680.92950.94460.97520.89870.82500.68730.64110.65600.8285
   2  60.91330.99320.94520.88810.91620.98920.92570.92320.81700.74380.73200.7612
   2  60.83840.90380.91310.88880.92700.99320.96180.89400.78510.72810.75000.9855
   1 100.98080.99640.96190.93470.92410.96040.89870.82070.66980.62140.63510.8082
   1 100.91680.99640.95020.88800.89240.97390.92820.92700.81130.73180.71460.7362
   1 100.79370.86190.86590.83980.86090.94630.93590.85860.78490.73120.75360.9964
   1 140.95420.99580.96550.93740.89770.88710.86190.80080.62780.56650.57230.7615
   1 140.88020.99580.95200.88220.87160.92800.93370.99310.84840.73890.70560.7277
   1 140.76140.85470.86860.84240.85230.91150.95980.85920.76990.69940.71550.9958
   1 190.92300.99660.98770.97060.91800.82910.84540.79030.61860.55140.55190.7408
   1 190.84960.99660.95710.89310.88040.87210.92410.98560.81570.71270.67650.6876
   1 190.78250.90090.92820.90880.91080.90630.99660.89480.77350.69440.70300.9517
   1 230.90760.98440.99590.99510.96290.88960.88350.79860.65700.59830.59060.7232
   1 230.87820.99590.99390.96710.96580.94570.96520.92040.77990.70360.67010.6743
   1 230.82230.92360.96240.95650.96160.94960.99590.93190.80350.73340.72760.8775
   1 270.84160.95010.98430.99970.97410.88210.85620.81600.65430.58360.56990.6824
   1 270.82520.97550.99970.99060.99580.95440.96130.97510.78400.68220.63460.6301
   1 270.72980.86880.94160.95170.97580.95400.99970.93320.80010.71560.70250.8675
   1 320.82080.94250.98250.99890.96350.86350.84760.80330.63130.56030.55080.6750
   1 320.80580.96780.98550.97200.97240.93520.96120.99890.84320.72900.68370.6729
   1 320.71430.85000.92270.94130.95880.93600.99890.90120.78190.70010.69150.8733
   1 360.89930.98790.99500.99140.94990.91090.88300.81440.61630.54640.54800.7524
   1 360.84760.99500.96720.91440.90800.95160.96700.99370.83910.72180.68250.6947
   1 360.70150.82850.88210.88310.89530.93330.99500.84530.71330.63760.64670.9165
   1 400.95390.99670.97100.94750.94300.96690.89220.79090.62640.57370.58340.7799
   1 400.87760.99670.93730.86330.89840.99190.94730.96210.79650.70610.68790.7230
   1 400.77710.86790.88350.86720.90770.98100.98100.84540.75960.69940.71550.9967
   1 450.94300.95960.92980.91110.96330.96920.88670.79240.64510.59790.60850.7786
   1 450.85740.93580.88730.84210.92710.96920.90140.87520.74190.67290.66150.6928
   1 450.78450.84880.85430.84810.92790.96500.92580.83090.75480.70300.72380.9692
   1 490.92210.94470.91450.89380.96370.95980.88030.82000.65820.60110.61170.7886
   1 490.83780.91350.87390.83620.92970.96370.90300.89840.73850.66390.65000.6844
```

Sheet 13

```
START
 COL  ----+----1----+----2----+----3----+----4----+----5----+----6----+----7----+----8

  1  490.76870.84350.85330.84020.93350.96370.92730.84260.73250.66960.68440.9074
  1  999
  1  24              1986 NUCLEAR SEASONAL FUEL FACTOR
  4     PCIBOT2       01 .6400
  4     PCIBOT3       01 .7000
  4     LIMERCK1      01 .7300
  4     SALEM1        01 .7000 09 .6900
  4     SALEM2        01 .5800 40 .6600
  1  999
  1  12    1986 SEASONAL FUEL COST FACTORS
 13                  01 01 1.031 13 1.041 27 1.072 40 1.103 COAL
 13                  02 01 1.161 13 1.129 27 1.214 40 1.299 HEAVY OIL 1% SULF.
 13                  03 01 1.036 13 1.022 27 1.099 40 1.175 LIGHT OIL
 13                  04 01 1.005 13 .9849 27 1.214 40 1.299 GAS
 13                  05 01 1.205 13 1.172 27 1.260 40 1.348 HEAVY OIL.5% SULF
  1  999
```

Data Request (1) (ii) (c)

Production Cost Model - Narrative of Input Data Evolutionary Changes

Item 1 (ii) (c)

As explained in the Addendum to "Description of Production Cost Program" contained in the response to Item 1 (ii) (a) two changes have been made to the Prod Cost model. The first change was to provide load models for all PJM members as independent companies to create a multi-area program. Prior to this change, the program functioned as a two area program with PECO as one area and the remainder of PJM as a second area. This change permits the program to determine on a bi-hourly basis the buying and selling members of PJM. Using this knowledge of what particular members are buying/selling members in an bi-hourly calculating period a more accurate prediction of the selling cost/replacement value for interchange transactions is determined. As a result, the Interchange billing price for PECO purchases and sales is a more accurate simulation of the costs PECO can expect to incur.

The second change was to model three dispatching areas within the PJM. The load models of the individual members are then assigned to one of the dispatching areas and economy interchange between areas (including 2 party transfers) is examined with respect to the transmission limitation curve for transfer between areas. This feature permits the ProdCost program to simulate the operational problems of energy transfer limitations and dispatch the areas to different cost levels when required. This added feature also provides a more accurate prediction of PECO's generation and fuel requirements for the period being investigated.

In addition to these two major changes, minor changes had been made to facilitate input data handling problems and to speed the data processing time. In addition, the output summary portion has had some changes to meet Department and Corporate requirements and incorporate changes to the PECO system.

Data Request (2) (i)

Actual Unit Data Report

Actual Data Report

Unit Name	Cromby	Eddystone	Schuylkill	Conemaugh
Unit Number	1	1	1	2
Date of Commercial Operation	1954	1960	1958	1971
Fuel Type	Coal & Oil	Coal	Oil	Coal
Name Plate Capacity (KW)	187,500	353,600	190,400	193,939
Architect/Engineer	PECO	PECO	PECO	Gilbert
Constructor	UE&C	UE&C	UE&C	Ebasco
Steam System Supplier	B & W	C. E.	C. E.	C. E.
Turbine Supplier	G. E.	West.	G. E.	G. E.

Unit Name	Cromby	Eddystone	Keystone	Peach Bottom
Unit Number	2	2	1	2
Date of Commercial Operation	1955	1960	1967	1974
Fuel Type	Oil	Coal	Coal	Nuclear
Name Plate Capacity (KW)	230,000	353,600	196,466	489,485
Architect/Engineer	PECO	PECO	Gilbert	Bechtel
Constructor	UE&C	UE&C	Ebasco	Bechtel
Steam System Supplier	C. E.	C. E.	C. E.	G. E.
Turbine Supplier	West.	G. E.	West.	G. E.

Unit Name	Delaware	Eddystone	Keystone	Peach Bottom
Unit Number	7	3	2	3
Date of Commercial Operation	1953	1974	1968	1974
Fuel Type	Oil	Oil	Coal	Nuclear
Name Plate Capacity (KW)	156,250	391,000	196,466	489,485
Architect/Engineer	PECO	UE&C	Gilbert	Bechtel
Constructor	UE&C	UE&C	Ebasco	Bechtel
Steam System Supplier	B & W	C. E.	C. E.	G. E.
Turbine Supplier	G. E.	West.	West.	G. E.

Unit Name	Delaware	Eddystone	Conemaugh	Salem
Unit Number	8	4	1	1
Date of Commercial Operation	1953	1974	1970	1977
Fuel Type	Oil	Oil	Coal	Nuclear
Name Plate Capacity (KW)	156,250	391,000	193,939	498,303
Architect/Engineer	PECO	UE&C	Gilbert	PSE&G
Constructor	UE&C	UE&C	Ebasco	UE&C
Steam System Supplier	B & W	C. E.	C. E.	West.
Turbine Supplier	G. E.	West.	G. E.	West.

Unit Name	Salem	Muddy Run
Unit Number	2	1,2,3,4,5,6
Date of Commercial Operation	1981	1967
Fuel Type	Nuclear	Hydro
Name Plate Capacity (KW)	498,303	100,000 EA.
Architect/Engineer	PSE&G	PECO
Constructor	UE&C	Arundel
Steam System Supplier	West.	N/A
Turbine Supplier	West.	B.L.H.

Unit Name	Limerick	Muddy Run
Unit Number	1	7,8
Date of Commercial Operation		1968
Fuel Type	Nuclear	Hydro
Name Plate Capacity (KW)	1,152,000	100,000 EA.
Architect/Engineer	Bechtel	PECO
Constructor	Bechtel	Arundel
Steam System Supplier	G. E.	N/A
Turbine Supplier	G. E.	B.L.H.

Unit Name	Eddystone	Schuylkill	Delaware	Salem
Unit Number	10,20	10	9	3
Date of Commercial Operation	1967	1969	1970	1971
Fuel Type	Oil	Oil	Oil	Oil
Name Plate Capacity (KW)	18,600 EA	18,600	21,250	17,824
Architect/Engineer	PECO	PECO	PECO	PSE&G
Constructor	PECO	PECO	PECO	UE&C
Steam System Supplier	N/A	N/A	N/A	N/A
Turbine Supplier	P&W	P&W	P&W	P&W

Unit Name	Eddystone	Schuylkill	Falls	Croydon
Unit Number	30,40	11	1,2,3	11,12,21,22 31,32,41,42
Date of Commercial Operation	1970	1971	1970	1974
Fuel Type	Oil	Oil	Oil	Oil
Name Plate Capacity (KW)	21,250 EA.	21,250 EA.	21,250 EA.	68,300 EA.
Architect/Engineer	PECO	PECO	PECO	PECO
Constructor	PECO	PECO	PECO	PECO
Steam System Supplier	N/A	N/A	N/A	N/A
Turbine Supplier	P&W	P&W	P&W	G. E.

Unit Name	Southwark	Chester	Moser
Unit Number	3,4,5	7,8,9	1,2,3
Date of Commercial Operation	1967	1969	1970
Fuel Type	Oil	Oil	Oil
Name Plate Capacity (KW)	18,600 EA.	18,600 EA.	21,250 EA.
Architect/Engineer	PECO	PECO	PECO
Constructor	PECO	PECO	PECO
Steam System Supplier	N/A	N/A	N/A
Turbine Supplier	P&W	P&W	P&W

Unit Name	Southwark	Delaware	Richmond
Unit Number	6	10,11,12	81,91,92
Date of Commercial Operation	1968	1969	1973
Fuel Type	Oil	Oil	Oil
Name Plate Capacity (KW)	18,600 EA.	18,600 EA.	65,300 EA.
Architect/Engineer	PECO	PECO	PECO
Constructor	PECO	PECO	PECO
Steam System Supplier	N/A	N/A	N/A
Turbine Supplier	P&W	P&W	G. E.

Data Request (2) (ii)

Actual Unit Data Report
5 Year Historical Data

Actual Unit Data Report
Item 2(ii)

Description	Years Ending 6/30/81	6/30/82	6/30/83	6/30/84	6/30/85
Nuclear Units					
Peach Bottom 2					
Net Winter Capacity (MW)	1051	1052	1065	1065	1065
Net Summer Capacity (MW)	1051	1051	1051	1051	1051
Planned Outage Factor %	22.2	18.1	0	17.5	100
Unit Derating Factor %	*	*	2.4	0.9	0
Equiv. Avail. Factor %	71.1	73.1	85.0	36.4	0
Net Capacity Factor %	63.5	53.0	82.9	33.7	0
Equiv. Forced Out. Rate %	6.4	4.4	7.0	53.9	0
Avg. Net Oper. Heat Rate	10,585	10,904	10,747	10,961	0
Avg. Net Oper. Cost	.354	.256	.244	.424	-
Peach Bottom 3					
Net Winter Capacity (MW)	1065	1050	1065	1065	1065
Net Summer Capacity (MW)	1035	1035	1035	1036	1035
Planned Outage Factor %	25.4	25.4	21.2	21.2	7.5
Unit Derating Factor %	*	*	2.6	0.9	2.2
Equiv. Avail. Factor %	62.7	69.7	59.4	66.3	82.8
Net Capacity Factor %	60.9	62.7	57.9	57.8	76.3
Equiv. Forced Out. Rate %	11.2	5.7	.6	7.6	6.3
Avg. Net Oper. Heat Rate	10,746	10,498	10,811	10,666	10,818
Avg. Net Oper. Cost	.354	.256	.244	.418	.608
Salem 1					
Net Winter Capacity (MW)	1100	1100	1100	1100	1100
Net Summer Capacity (MW)	1079	1079	1081	1081	1079
Planned Outage Factor %	13.2	25.4	19.5	24.7	2.2
Unit Derating Factor %	*	*	1.1	0.9	4.2
Equiv. Avail. Factor %	65.7	56.6	38.7	59.8	60.9
Net Capacity Factor %	43.7	60.0	36.6	59.3	59.8
Equiv. Forced Out. Rate %	17.4	17.4	42.6	20.0	36.7
Avg. Net Oper. Heat Rate	10,967	11,272	10,918	10,517	10,580
Avg. Net Oper. Cost	.265	.300	.468	.538	.744
Salem 2					
Net Winter Capacity (MW)		1120	1120	1120	1120
Net Summer Capacity (MW)		1106	1107	1107	1106
Planned Outage Factor %		0	34.8	0	19.7
Unit Derating Factor %		*	14.9	0.8	2.0
Equiv. Avail. Factor %		97.8	38.3	26.5	30.5
Net Capacity Factor %		87.6	37.5	23.8	28.7
Equiv. Forced Out. Rate %		17.1	22.3	71.9	61.8
Avg. Net Oper. Heat Rate		10,583	11,430	11,122	10,988
Avg. Net Oper. Cost		.512	.506	-	.597

Description	Years Ending 6/30/81	6/30/82	6/30/83	6/30/84	6/30/85
Coal Fired Units					
Eddystone 1					
Net Winter Capacity (MW)	321	321	321	321	319
Net Summer Capacity (MW)	301	301	301	304	311
Planned Outage Factor %	33.3	27.6	28.5	22.6	0
Unit Derating Factor %	*	*	2.8	6.6	6.7
Equiv. Avail. Factor %	26.0	45.9	18.6	21.3	68.8
Net Capacity Factor %	29.2	41.4	14.6	16.3	55.8
Equiv. Forced Out. Rate %	59.5	31.3	67.6	27.0	29.8
Avg. Net Oper. Heat Rate	11,087	11,489	12,282	12,526	11,047
Avg. Net Oper. Cost	1.852	2.073	2.024	2.079	2.113
Eddystone 2					
Net Winter Capacity (MW)	343	343	343	343	333
Net Summer Capacity (MW)	334	334	334	330	324
Planned Outage Factor %	18.1	28.4	0	16.1	31.8
Unit Derating Factor %	*	*	8.0	2.5	11.0
Equiv. Avail. Factor %	59.4	45.2	70.9	35.3	42.1
Net Capacity Factor %	54.4	41.4	57.6	27.3	35.4
Equiv. Forced Out. Rate %	25.4	35.0	25.2	37.8	36.3
Avg. Net Oper. Heat Rate	10,310	10,523	10,663	11,418	11,097
Avg. Net Oper. Cost	1.852	2.073	2.024	2.079	2.113
Cromby 1					
Net Winter Capacity (MW)	162	162	153	153	147
Net Summer Capacity (MW)	150	152	152	150	144
Planned Outage Factor %	17.5	16.5	16.3	1.0	21.5
Unit Derating Factor %	*	*	1.7	5.2	2.5
Equiv. Avail. Factor %	70.7	68.1	68.1	86.5	64.9
Net Capacity Factor %	56.0	54.9	55.8	72.2	47.8
Equiv. Forced Out. Rate %	9.5	13.8	16.0	6.2	15.5
Avg. Net Oper. Heat Rate	10,274	10,269	10,452	10,965	11,052
Avg. Net Oper. Cost	1.742	1.957	1.938	1.928	2.046
Keystone 1					
Net Winter Capacity (MW)	850	850	850	850	850
Net Summer Capacity (MW)	832	833	850	850	850
Planned Outage Factor %	12.2	12.2	8.1	18.7	0
Unit Derating Factor %	*	*	1.3	1.3	0.9
Equiv. Avail. Factor %	71.7	67.3	73.5	79.0	87.1
Net Capacity Factor %	71.6	54.3	69.4	75.5	83.9
Equiv. Forced Out. Rate %	17.5	21.8	18.5	10.8	12.8
Avg. Net Oper. Heat Rate	10,311	9,562	10,239	9,775	9,563
Avg. Net Oper. Cost	1.088	1.174	1.230	1.165	1.213

Description	Years Ending 6/30/81	6/30/82	6/30/83	6/30/84	6/30/85
Keystone 2					
Net Winter Capacity (MW)	850	850	850	850	850
Net Summer Capacity (MW)	834	835	850	850	850
Planned Outage Factor %	14.8	5.8	16.0	16.0	25.7
Unit Derating Factor %	*	*	2.8	1.4	1.7
Equiv. Avail. Factor %	72.3	76.8	66.2	80.3	52.9
Net Capacity Factor %	62.8	74.3	60.9	76.5	50.4
Equiv. Forced Out. Rate %	13.4	17.1	18.3	17.2	22.2
Avg. Net Oper. Heat Rate	9,610	9,771	10,526	9,856	10,053
Avg. Net Oper. Cost	1.088	1.174	1.230	1.165	1.213
Conemaugh 1					
Net Winter Capacity (MW)	851	851	850	850	850
Net Summer Capacity (MW)	833	842	850	850	850
Planned Outage Factor %	9.0	19.0	15.6	10.2	10.2
Unit Derating Factor %	*	*	3.8	2.3	2.7
Equiv. Avail. Factor %	65.5	71.8	61.7	79.1	75.7
Net Capacity Factor %	53.4	65.6	56.4	74.8	71.2
Equiv. Forced Out. Rate %	31.4	32.3	19.2	10.8	15.5
Avg. Net Oper. Heat Rate	10,211	10,118	9,759	9,478	9,572
Avg. Net Oper. Cost	1.491	1.723	1.565	1.270	1.509
Conemaugh 2					
Net Winter Capacity (MW)	851	850	850	850	850
Net Summer Capacity (MW)	834	838	850	850	850
Planned Outage Factor %	6.0	13.7	0	0	10.1
Unit Derating Factor %	*	*	5.3	4.9	4.2
Equiv. Avail. Factor %	69.8	54.1	69.7	75.2	79.6
Net Capacity Factor %	65.6	45.5	64.1	70.6	74.7
Equiv. Forced Out. Rate %	29.3	35.2	26.8	16.0	11.5
Avg. Net Oper. Heat Rate	10,218	10,321	10,019	9,555	9,779
Avg. Net Oper. Cost	1.491	1.723	1.565	1.270	1.509
Oil Fired Steam Units					
Schuylkill 1					
Net Winter Capacity (MW)	175	175	175	175	175
Net Summer Capacity (MW)	166	166	166	166	166
Planned Outage Factor %	9.7	14.2	13.3	31.4	0
Unit Derating Factor %	*	*	0.4	2.2	3.2
Equiv. Avail. Factor %	75.6	62.6	28.8	46.3	60.3
Net Capacity Factor %	38.8	25.3	9.9	28.5	21.3
Equiv. Forced Out. Rate %	12.4	34.8	73.1	24.9	26.8
Avg. Net Oper. Heat Rate	10,397	10,785	10,903	10,747	10,984
Avg. Net Oper. Cost	5.694	5.409	5.392	5.301	5.211

Description	Years Ending 6/30/81	6/30/82	6/30/83	6/30/84	6/30/85
Eddystone 3					
Net Winter Capacity (MW)	380	380	380	380	380
Net Summer Capacity (MW)	380	379	377	377	380
Planned Outage Factor %	2.3	3.1	13.4	15.2	0
Unit Derating Factor %	*	*	0.7	0.9	0.6
Equiv. Avail. Factor %	70.2	81.0	76.7	67.8	89.5
Net Capacity Factor %	22.4	18.0	13.8	26.4	24.3
Equiv. Forced Out. Rate %	38.9	14.5	11.8	13.9	11.6
Avg. Net Oper. Heat Rate	12,232	13,724	15,158	12,125	12,840
Avg. Net Oper. Cost	6.324	7.283	7.423	6.154	6.405
Eddystone 4					
Net Winter Capacity (MW)	380	380	380	380	380
Net Summer Capacity (MW)	380	380	378	378	380
Planned Outage Factor %	5.7	6.9	5.1	0	29.4
Unit Derating Factor %	*	*	0.5	1.6	5.3
Equiv. Avail. Factor %	76.0	79.8	78.5	91.7	61.7
Net Capacity Factor %	24.4	19.0	14.3	30.4	14.9
Equiv. Forced Out. Rate %	23.9	12.7	7.4	5.6	16.6
Avg. Net Oper. Heat Rate	12,072	13,667	14,042	12,349	12,981
Avg. Net Oper. Cost	6.324	7.283	7.423	6.154	6.405
Cromby 2					
Net Winter Capacity (MW)	224	224	211	211	211
Net Summer Capacity (MW)	201	210	210	210	201
Planned Outage Factor %	2.9	4.8	0	8.5	*
Unit Derating Factor %	*	*	2.1	3.9	2.1
Equiv. Avail. Factor %	85.3	76.7	74.8	76.8	73.8
Net Capacity Factor %	48.9	36.7	36.3	40.9	36.9
Equiv. Forced Out. Rate %	8.5	18.1	22.2	12.0	20.2
Avg. Net Oper. Heat Rate	10,273	10,380	10,282	10,372	10,373
Avg. Net Oper. Cost	5.340	5.055	4.771	5.029	5.131
Delaware 7					
Net Winter Capacity (MW)	128	128	128	128	128
Net Summer Capacity (MW)	126	126	124	124	126
Planned Outage Factor %	5.0	11.7	19.7	2.9	10.1
Unit Derating Factor %	*	*	2.0	1.2	0.1
Equiv. Avail. Factor %	77.2	74.1	38.1	74.0	80.4
Net Capacity Factor %	77.3	28.1	10.0	41.1	35.0
Equiv. Forced Out. Rate %	18.0	13.8	31.7	25.2	5.7
Avg. Net Oper. Heat Rate	10,742	10,840	11,929	10,604	10,730
Avg. Net Oper. Cost	5.756	6.008	6.001	5.428	5.378

Description	Years Ending 6/30/81	6/30/82	6/30/83	6/30/84	6/30/85
Delaware 8					
Net Winter Capacity (MW)	128	128	128	128	128
Net Summer Capacity (MW)	126	124	124	124	124
Planned Outage Factor %	21.4	3.4	4.9	8.4	11.3
Unit Derating Factor %	*	*	2.1	2.3	6.9
Equiv. Avail. Factor %	53.2	69.0	68.9	67.8	65.4
Net Capacity Factor %	19.8	19.0	19.0	26.1	25.0
Equiv. Forced Out. Rate %	48.7	29.3	14.1	19.0	28.6
Avg. Net Oper. Heat Rate	11,429	11,916	11,623	10,924	10,192
Avg. Net Oper. Cost	5.756	6.008	6.001	5.428	5.378

Actual Unit Data Report
Item 2(ii)

Description	Years 1980	1981	1982	1983	1984
Richmond 81					
Net Winter Capacity	64	66	66	66	66
Net Summer Capacity	48	48	58	58	58
Planned Outage Factor	19.1	0.0	0	0.1	0
Unit Derating Factor	*	*	0	0.3	0
Equiv. Avail. Factor	70.7	73.2	19.8	97.3	93.5
Net Capacity Factor	12.1	6.5	0.4	7.9	2.0
Equiv. Forced Out. Rate	49.4	39.6	99.2	7.4	64.0
Richmond 91					
Net Winter Capacity	64	66	66	66	66
Net Summer Capacity	48	48	56	58	58
Planned Outage Factor	31.1	0.2	0	4.5	0
Unit Derating Factor	*	*	0.3	1.5	0
Equiv. Avail. Factor	61.0	88.2	95.7	76.7	90.0
Net Capacity Factor	9.5	7.9	2.7	5.2	3.4
Equiv. Forced Out. Rate	51.6	45.1	35.4	64.4	18.4
Richmond 92					
Net Winter Capacity	64	66	66	66	66
Net Summer Capacity	48	48	55	58	58
Planned Outage Factor	29.4	11.2	23.1	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	45.0	83.7	71.7	91.9	95.2
Net Capacity Factor	7.4	6.8	2.5	7.3	3.5
Equiv. Forced Out. Rate	89.7	57.2	41.3	36.9	21.1
Croydon 11					
Net Winter Capacity	63	63	63	63	58
Net Summer Capacity	49	49	56	58	51
Planned Outage Factor	40.2	2.4	3.1	0	0
Unit Derating Factor	*	*	16.5	31.5	16.5
Equiv. Avail. Factor	47.1	89.3	50.8	57.8	74.8
Net Capacity Factor	8.1	6.1	0.9	4.0	3.8
Equiv. Forced Out. Rate	75.8	84.6	375.1	279.2	165.3
Croydon 12					
Net Winter Capacity	63	63	63	63	58
Net Summer Capacity	49	49	55	57	51
Planned Outage Factor	38.8	33.9	8.6	0	7.0
Unit Derating Factor	*	*	18.3	38.5	17.3
Equiv. Avail. Factor	43.8	64.1	69.5	59.6	70.7
Net Capacity Factor	7.0	1.7	1.8	4.3	3.3
Equiv. Forced Out. Rate	106.3	61.4	424.3	335.8	255.5

Description	Years 1980	1981	1982	1983	1984
Croydon 21					
Net Winter Capacity	63	63	63	63	61
Net Summer Capacity	49	49	56	57	55
Planned Outage Factor	12.8	31.4	11.9	0	0
Unit Derating Factor	*	*	13.5	19.1	13.1
Equiv. Avail. Factor	51.1	44.5	62.8	67.5	78.7
Net Capacity Factor	2.2	0.3	3.1	10.4	11.1
Equiv. Forced Out. Rate	719.2	119.3	148.6	111.6	82.2
Croydon 22					
Net Winter Capacity	63	63	63	63	56
Net Summer Capacity	49	49	52	57	48
Planned Outage Factor	28.8	2.5	8.9	4.9	0
Unit Derating Factor	*	*	14.7	21.0	0.9
Equiv. Avail. Factor	56.1	57.3	74.9	29.1	53.7
Net Capacity Factor	10.1	3.6	1.4	1.3	2.2
Equiv. Forced Out. Rate	58.9	163.2	255.6	555.5	91.5
Croydon 31					
Net Winter Capacity	63	63	63	63	58
Net Summer Capacity	49	49	54	57	51
Planned Outage Factor	32.1	15.5	0.1	8.3	0
Unit Derating Factor	*	*	10.8	28.3	15.9
Equiv. Avail. Factor	51.9	73.3	74.4	59.2	70.2
Net Capacity Factor	9.0	4.7	1.5	4.5	4.0
Equiv. Forced Out. Rate	99.1	58.3	201.6	299.9	170.1
Croydon 32					
Net Winter Capacity	63	63	63	63	61
Net Summer Capacity	49	49	57	57	55
Planned Outage Factor	19.3	0.2	27.4	9.3	0
Unit Derating Factor	*	*	3.5	15.1	7.9
Equiv. Avail. Factor	47.8	96.9	65.1	62.2	76.0
Net Capacity Factor	2.0	0.9	2.4	11.6	10.6
Equiv. Forced Out. Rate	734.9	2.0	92.1	92.8	75.5
Croydon 41					
Net Winter Capacity	63	63	63	63	58
Net Summer Capacity	49	49	57	57	51
Planned Outage Factor	22.2	0	0	5.1	13.4
Unit Derating Factor	*	*	13.4	21.7	11.5
Equiv. Avail. Factor	59.9	78.2	36.9	57.8	67.4
Net Capacity Factor	9.9	5.2	0.5	4.4	3.9
Equiv. Forced Out. Rate	95.1	112.8	151.5	162.1	160.7

Description	Years 1980	1981	1982	1983	1984
Croydon 42					
Net Winter Capacity	63	63	63	63	61
Net Summer Capacity	49	49	55	57	55
Planned Outage Factor	0	0	17.3	0.1	0
Unit Derating Factor	*	*	14.0	15.9	9.7
Equiv. Avail. Factor	50.4	96.0	66.8	60.6	81.5
Net Capacity Factor	0.7	0.2	2.9	10.9	11.7
Equiv. Forced Out. Rate	347.6	83.5	257.6	98.4	67.3
Eddystone 10					
Net Winter Capacity	17	18	13	14	18
Net Summer Capacity	13	13	13	14	16
Planned Outage Factor	0	0.9	0	0.9	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	96.9	93.8	94.9	96.2	80.0
Net Capacity Factor	1.0	1.3	1.2	1.6	1.1
Equiv. Forced Out. Rate	65.0	80.4	68.5	45.1	90.6
Eddystone 20					
Net Winter Capacity	17	18	13	14	18
Net Summer Capacity	13	13	13	14	16
Planned Outage Factor	4.4	0.3	0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	89.8	89.6	87.2	77.6	92.4
Net Capacity Factor	0.9	1.4	0.8	1.0	1.8
Equiv. Forced Out. Rate	81.6	85.4	81.4	95.5	57.8
Eddystone 30					
Net Winter Capacity	19	20	15	16	20
Net Summer Capacity	15	15	15	16	17
Planned Outage Factor	0.2	0.4	0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	94.5	92.3	93.3	91.8	98.3
Net Capacity Factor	1.3	1.8	1.4	1.9	2.2
Equiv. Forced Out. Rate	74.5	64.0	69.8	66.7	35.2
Eddystone 40					
Net Winter Capacity	19	20	15	16	20
Net Summer Capacity	15	15	15	16	17
Planned Outage Factor	0.2	1.0	2.0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	98.7	97.4	95.8	94.6	41.8
Net Capacity Factor	1.5	1.8	1.4	2.1	0.3
Equiv. Forced Out. Rate	27.9	38.8	25.9	51.2	99.4

(4)

Description	Years 1980	1981	1982	1983	1984
Southwark 3					
Net Winter Capacity	17	18	18	18	18
Net Summer Capacity	13	13	16	16	15
Planned Outage Factor	0.5	0.5	0	0	0
Unit Derating Factor	*	*	0.0	0	0
Equiv. Avail. Factor	81.8	93.0	91.2	69.2	63.3
Net Capacity Factor	2.3	1.2	0.8	0.9	0.9
Equiv. Forced Out. Rate	88.3	82.1	89.0	85.5	96.4
Southwark 4					
Net Winter Capacity	17	18	18	18	18
Net Summer Capacity	13	13	16	16	16
Planned Outage Factor	1.8	0.4	0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	92.1	97.2	92.3	99.0	87.7
Net Capacity Factor	1.4	1.4	0.7	1.3	1.2
Equiv. Forced Out. Rate	82.5	64.0	81.5	29.0	86.6
Southwark 5					
Net Winter Capacity	17	18	18	18	18
Net Summer Capacity	13	13	16	16	15
Planned Outage Factor	1.9	0.4	0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	97.0	98.3	89.4	96.6	97.0
Net Capacity Factor	2.5	1.3	1.1	1.2	1.7
Equiv. Forced Out. Rate	18.5	49.7	88.2	58.6	10.9
Southwark 6					
Net Winter Capacity	17	18	18	18	18
Net Summer Capacity	13	13	16	16	15
Planned Outage Factor	2.2	0.3	0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	92.3	87.5	89.6	94.1	91.9
Net Capacity Factor	2.1	1.2	0.8	1.1	1.1
Equiv. Forced Out. Rate	71.8	91.8	90.5	76.5	72.2
Chester 7					
Net Winter Capacity	17	18	18	18	18
Net Summer Capacity	13	15	16	16	15
Planned Outage Factor	6.2	2.3	0	0	0
Unit Derating Factor	*	*	0	0	2.2
Equiv. Avail. Factor	88.8	97.2	97.6	94.0	88.5
Net Capacity Factor	1.0	1.6	0.8	0.9	0.9
Equiv. Forced Out. Rate	83.6	15.8	40.4	82.5	104.1

(5)

Description	Years 1980	1981	1982	1983	1984
Chester 8					
Net Winter Capacity	17	18	18	18	18
Net Summer Capacity	13	15	16	16	16
Planned Outage Factor	3.6	1.1	0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	93.8	96.0	97.1	68.9	70.3
Net Capacity Factor	0.9	1.2	0.7	0.4	1.0
Equiv. Forced Out. Rate	65.7	90.1	48.0	98.2	94.5
Chester 9					
Net Winter Capacity	17	18	18	18	18
Net Summer Capacity	13	13	16	16	16
Planned Outage Factor	4.5	1.0	0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	92.9	93.8	93.3	92.8	76.1
Net Capacity Factor	1.2	1.5	1.0	0.9	1.3
Equiv. Forced Out. Rate	62.0	75.9	68.5	76.4	92.5
Delaware 9					
Net Winter Capacity	19	19	20	20	20
Net Summer Capacity	15	19	17	17	17
Planned Outage Factor	0.3	0.7	0.0	0	0
Unit Derating Factor	*	*	0.0	0	0
Equiv. Avail. Factor	93.3	75.3	94.5	99.3	79.4
Net Capacity Factor	1.1	1.2	0.8	1.7	1.5
Equiv. Forced Out. Rate	76.0	94.2	68.5	2.1	88.9
Delaware 10					
Net Winter Capacity	17	17	18	18	18
Net Summer Capacity	13	17	15	16	17
Planned Outage Factor	0.2	0.3	0.0	0	0
Unit Derating Factor	*	*	0.2	0	0
Equiv. Avail. Factor	95.6	92.6	92.6	94.8	93.5
Net Capacity Factor	1.1	0.9	0.5	0.8	1.1
Equiv. Forced Out. Rate	73.3	85.0	88.3	72.6	82.2
Delaware 11					
Net Winter Capacity	17	17	18	18	18
Net Summer Capacity	13	17	15	16	16
Planned Outage Factor	0.1	3.7	0.0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	97.5	93.9	77.3	98.3	68.8
Net Capacity Factor	1.0	1.1	0.4	1.2	1.6
Equiv. Forced Out. Rate	60.9	63.1	92.8	42.9	93.8

Description	Years 1980	1981	1982	1983	1984
Delaware 12					
Net Winter Capacity	17	17	18	18	18
Net Summer Capacity	13	17	16	16	17
Planned Outage Factor	0.9	0.6	0.0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	53.3	58.2	94.8	94.4	70.3
Net Capacity Factor	0.3	0.4	0.5	1.1	0.6
Equiv. Forced Out. Rate	98.4	98.7	80.4	62.8	97.8
Schuylkill 10					
Net Winter Capacity	17	18	18	18	18
Net Summer Capacity	13	13	16	16	17
Planned Outage Factor	1.5	6.4	0.4	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	93.0	67.7	79.4	94.1	91.7
Net Capacity Factor	2.3	0.3	0.6	1.1	1.9
Equiv. Forced Out. Rate	66.3	98.8	78.4	75.8	73.8
Schuylkill 11					
Net Winter Capacity	19	20	20	20	20
Net Summer Capacity	15	15	18	17	18
Planned Outage Factor	2.5	1.1	0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	96.2	90.2	49.3	75.2	60.3
Net Capacity Factor	2.6	0.2	0.6	1.1	2.2
Equiv. Forced Out. Rate	26.1	30.9	98.4	93.2	91.7
Moser 1					
Net Winter Capacity	19	20	20	20	20
Net Summer Capacity	15	15	19	18	19
Planned Outage Facto	0.0	3.1	0.1	1.2	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	96.7	95.7	97.0	93.6	86.4
Net Capacity Factor	4.4	4.2	1.6	2.3	1.8
Equiv. Forced Out. Rate	42.5	22.2	4.9	59.6	82.0
Moser 2					
Net Winter Capacity	19	20	20	20	20
Net Summer Capacity	15	15	19	18	19
Planned Outage Factor	0.3	1.8	0.1	1.2	0
Unit Derating Factor	*	*	0.1	0	0
Equiv. Avail. Factor	84.9	94.5	94.0	94.2	89.9
Net Capacity Factor	2.7	3.1	1.6	1.7	1.0
Equiv. Forced Out. Rate	86.1	13.8	55.5	54.7	85.0

Description	Years 1980	1981	1982	1983	1984
Moser 3					
Net Winter Capacity	19	20	20	20	20
Net Summer Capacity	15	15	19	18	19
Planned Outage Factor	0.4	1.9	0.1	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	92.3	96.8	97.8	97.3	95.9
Net Capacity Factor	3.8	3.4	1.2	1.9	2.0
Equiv. Forced Out. Rate	67.7	30.1	43.9	46.0	43.2
Falls 1					
Net Winter Capacity	19	20	20	20	20
Net Summer Capacity	15	15	17	18	18
Planned Outage Factor	0	0.1	2.3	0	0.8
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	94.0	98.4	95.5	96.6	95.5
Net Capacity Factor	1.6	2.1	0.6	0.1	1.9
Equiv. Forced Out. Rate	76.8	40.0	37.6	96.1	29.3
Falls 2					
Net Winter Capacity	19	20	20	20	20
Net Summer Capacity	15	15	16	18	18
Planned Outage Factor	0	0.1	0	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	81.9	98.6	69.0	53.3	89.5
Net Capacity Factor	1.8	1.9	0.7	1.3	1.9
Equiv. Forced Out. Rate	90.6	37.1	97.0	96.3	76.6
Falls 3					
Net Winter Capacity	19	20	20	20	20
Net Summer Capacity	15	15	16	18	18
Planned Outage Factor	0	0	0.1	0	0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	99.9	97.6	98.8	94.2	92.5
Net Capacity Factor	1.9	1.7	0.4	0.1	1.7
Equiv. Forced Out. Rate	0	37.2	58.5	94.7	68.5
Muddy Run 1					
Net Winter Capacity	110	110	110	110	110
Net Summer Capacity	110	110	110	110	110
Planned Outage Factor	0	12.3	0.0	8.0	12.0
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	98.4	83.5	90.4	83.4	82.0
Net Capacity Factor	18.3	15.4	16.6	15.2	15.8
Equiv. Forced Out. Rate	0.3	7.6	16.7	10.3	2.3

Description	Years 1980	1981	1982	1983	1984
Muddy Run 2					
Net Winter Capacity	110	110	110	110	110
Net Summer Capacity	110	110	110	110	110
Planned Outage Factor	0	12.3	0	8.0	12.0
Unit Derating Factor	*	*	0.1	0	0
Equiv. Avail. Factor	98.2	82.9	75.3	86.0	81.1
Net Capacity Factor	18.4	15.3	12.9	16.0	12.3
Equiv. Forced Out. Rate	0.4	7.8	57.9	0.6	17.8
Muddy Run 3					
Net Winter Capacity	110	110	110	110	110
Net Summer Capacity	110	110	110	110	110
Planned Outage Factor	0	15.8	0	8.1	3.9
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	87.9	75.6	95.0	74.7	91.4
Net Capacity Factor	17.1	13.7	17.2	12.7	16.1
Equiv. Forced Out. Rate	25.5	22.0	1.2	4.6	8.0
Muddy Run 4					
Net Winter Capacity	110	110	110	110	110
Net Summer Capacity	110	110	110	110	110
Planned Outage Factor	0	15.8	0	8.1	3.9
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	90.3	74.9	90.7	60.8	91.3
Net Capacity Factor	17.2	13.6	16.0	10.7	15.4
Equiv. Forced Out. Rate	9.5	16.5	5.9	33.5	5.5
Muddy Run 5					
Net Winter Capacity	110	110	110	110	110
Net Summer Capacity	110	110	110	110	110
Planned Outage Factor	45.5	0	18.6	0	34.8
Unit Derating Factor	*	*	0.0	0	0
Equiv. Avail. Factor	53.0	97.1	77.6	87.7	50.7
Net Capacity Factor	4.9	15.6	14.7	11.3	10.8
Equiv. Forced Out. Rate	6.5	0.8	2.5	36.4	2.2
Muddy Run 6					
Net Winter Capacity	110	110	110	110	110
Net Summer Capacity	110	110	110	110	110
Planned Outage Factor	43.9	0	18.6	0	34.8
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	55.1	95.8	77.7	90.5	50.0
Net Capacity Factor	10.4	16.3	14.3	15.2	10.6
Equiv. Forced Out. Rate	1.9	6.3	0	4.2	9.6

Description	Years 1980	1981	1982	1983	1984
Muddy Run 7					
Net Winter Capacity	110	110	110	110	110
Net Summer Capacity	110	110	110	110	110
Planned Outage Factor	15.6	0	21.6	7.7	0.9
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	74.5	81.6	72.9	53.0	93.9
Net Capacity Factor	6.9	12.8	12.1	10.3	15.5
Equiv. Forced Out. Rate	21.0	47.6	4.9	12.1	1.0
Muddy Run 8					
Net Winter Capacity	110	110	110	110	110
Net Summer Capacity	110	110	110	110	110
Planned Outage Factor	15.6	0	21.6	15.0	0.9
Unit Derating Factor	*	*	0	0	0
Equiv. Avail. Factor	80.8	83.3	72.0	48.1	94.8
Net Capacity Factor	15.7	12.5	13.1	10.2	17.3
Equiv. Forced Out. Rate	0.8	42.7	9.6	3.7	0.4
Salem 3					
Net Winter Capacity	48	48	48	48	48
Net Summer Capacity	38	38	43	43	43
Planned Outage Factor	0	6.1	0	0	0
Unit Derating Factor	*	*	3.1	1.0	1.1
Equiv. Avail. Factor	89.3	81.5	96.0	91.3	92.3
Net Capacity Factor	0.7	0.5	0.3	1.8	1.1
Equiv. Forced Out. Rate	186.3	669.9	139.8	77.2	66.7

Combustion Turbine
Historical Summary Report

	1980	1981	1982	1983	1984	5 Yr. Avg.
Schuylkill						
Avg. Net Oper. Heat Rate	14,581	14,878	15,522	15,365	15,265	15,122
Avg. Cost	7.504	9.859	15.063	10.005	9.686	10.423
Eddystone						
Avg. Net Oper. Heat Rate	13,977	15,876	14,406	15,062	15,487	14,962
Avg. Cost	7.107	10.842	9.963	9.331	9.579	9.364
Chester						
Avg. Net Oper. Heat Rate	14,958	15,118	14,461	15,052	15,329	14,984
Avg. Cost	7.043	9.880	10.281	9.975	9.479	9.332
Delaware						
Avg. Net Oper. Heat Rate	14,280	13,160	14,402	15,012	14,338	14,238
Avg. Cost	8.099	9.496	10.456	9.484	9.070	9.321
Southwark						
Avg. Net Oper. Heat Rate	14,519	15,714	14,856	15,257	15,876	15,244
Avg. Cost	8.315	11.152	10.498	9.639	10.009	9.923
Falls						
Avg. Net Oper. Heat Rate	14,692	14,678	14,341	14,694	14,701	14,621
Avg. Cost	6.855	9.612	10.014	9.867	9.350	9.140
Moser						
Avg. Net Oper. Heat Rate	14,180	14,288	14,709	14,157	14,647	14,396
Avg. Cost	7.631	9.965	10.249	9.161	9.118	9.225
Salem						
Avg. Net Oper. Heat Rate	15,930	16,004	19,164	25,244	17,207	18,710
Avg. Cost	8.392	10.753	11.708	10.431	9.138	10.084
Richmond						
Avg. Net Oper. Heat Rate	12,439	12,668	13,058	12,995	12,637	12,759
Avg. Cost	6.618	8.605	8.920	7.867	7.976	7.997
Croydon						
Avg. Net Oper. Heat Rate	12,520	12,966	12,582	11,965	12,091	12,425
Avg. Cost	5.906	7.849	8.257	7.382	7.411	7.361

Data Request (3) (i)

Comparative Data
5 Year Historic Average Versus Test Year Projection

Comparison Unit Data Report
Item 3(i)

Description	Historical Average	6/30/87	6/30/88	6/30/89	Average
Nuclear Units					
Peach Bottom No. 2					
Planned Outage Factor %	31.6	28.8	0.0	26.9	18.5
Equiv. Avail. Factor %	53.1	59.4	85.5	57.5	67.5
Net Capacity Factor %	46.6	59.3	85.4	57.1	67.3
Avg. Net. Oper. Heat Rate	10,769	10,812	10,812	10,812	10,812
Avg. Oper. Cost	.304	.932	.903	.995	.938
Peach Bottom No. 3					
Planned Outage Factor %	20.1	17.3	92.1	0.0	36.4
Equiv. Avail. Factor %	68.2	63.4	11.3	86.4	53.7
Net Capacity Factor %	63.1	63.1	11.3	86.5	53.7
Avg. Net. Oper. Heat Rate	10,715	10,829	10,824	10,824	10,827
Avg. Oper. Cost	.387	.994	2.000	0.898	.994
Salem No. 1					
Planned Outage Factor %	17.0	0.0	42.2	30.7	24.3
Equiv. Avail. Factor %	56.3	80.8	49.1	58.9	62.9
Net Capacity Factor %	51.9	80.3	48.7	58.4	62.5
Avg. Net. Oper. Heat Rate	10,839	10,738	10,739	10,737	10,738
Avg. Oper. Cost	.475	.889	.990	.934	.930
Salem No. 2					
Planned Outage Factor %	13.6	32.6	28.8	0.0	20.5
Equiv. Avail. Factor %	44.5	54.0	56.7	81.5	64.1
Net Capacity Factor %	41.1	53.4	56.2	80.7	63.5
Avg. Net. Oper. Heat Rate	10,899	10,741	10,748	10,747	10,746
Avg. Oper. Cost	.527	.881	.882	.904	.892
Limerick No. 1					
Planned Outage Factor %		27.4	9.0	30.7	22.4
Equiv. Avail. Factor %	Not	56.4	71.7	57.4	61.8
Net Capacity Factor %	Commercial	55.8	71.7	57.0	61.6
Avg. Net. Oper. Heat Rate		10,818	10,806	10,815	10,812
Avg. Oper. Cost		.802	.540	.543	.621
Coal Fired Units					
Eddystone No. 1					
Planned Outage Factor %	22.4	0.0	26.9	17.3	14.7
Equiv. Avail. Factor %	36.1	70.7	52.4	59.9	61.0
Net Capacity Factor %	31.5	50.1	38.6	43.1	43.9
Avg. Net. Oper. Heat Rate	11,686	10,229	10,293	10,240	10,251
Avg. Oper. Cost	2.025	2.128	2.280	2.464	2.297

Description	Historical Average	Years Ending 6/30/87	6/30/88	6/30/89	Average
Eddystone No. 2					
Planned Outage Factor %	18.9	28.8	24.9	0.0	17.9
Equiv. Avail. Factor %	50.6	53.9	58.8	75.3	62.7
Net Capacity Factor %	43.2	37.2	41.3	53.1	43.9
Avg. Net. Oper. Heat Rate	10,802	10,436	10,286	10,191	10,290
Avg. Oper. Cost	2.025	2.128	2.280	2.464	2.297
Cromby No. 1					
Planned Outage Factor %	14.6	7.7	0.0	19.2	9.0
Equiv. Avail. Factor %	71.7	81.8	88.9	70.8	80.5
Net Capacity Factor %	57.3	54.6	62.1	46.6	54.4
Avg. Net. Oper. Heat Rate	10,602	10,889	10,848	11,065	10,922
Avg. Oper. Cost	1,919	2.100	2.257	2.460	2.262
Keystone No.1					
Planned Outage Factor %	10.2	7.7	7.7	9.6	8.3
Equiv. Avail. Factor %	75.7	76.0	78.6	74.4	76.3
Net Capacity Factor %	70.9	70.3	72.9	68.9	70.7
Avg. Net. Oper. Heat Rate	9,891	9,708	9,714	9,703	9,709
Avg. Oper. Cost	1.172	1.290	1.389	1.497	1.391
Keystone No. 2					
Planned Outage Factor %	15.7	0.0	11.5	13.4	8.3
Equiv. Avail. Factor %	69.7	74.8	66.1	65.6	68.8
Net Capacity Factor %	66.4	69.6	61.8	61.1	64.2
Avg. Net. Oper. Heat Rate	9,938	9,704	9,710	9,707	9,707
Avg. Oper. Cost	1.172	1.291	1.392	1.504	1.391
Conemaugh No. 1					
Planned Outage Factor %	12.8	0.0	9.6	11.5	7.0
Equiv. Avail. Factor %	69.8	73.6	65.1	61.7	66.8
Net Capacity Factor %	64.3	68.8	61.2	57.3	62.4
Avg. Net. Oper. Heat Rate	9,801	9,632	9,649	9,674	9,650
Avg. Oper. Cost	1.499	1.594	1.722	1.858	1.717
Conemaugh No. 2					
Planned Outage Factor %	6.0	9.6	11.5	9.6	10.2
Equiv. Avail. Factor %	69.7	65.1	65.4	65.1	65.2
Net Capacity Factor %	64.1	60.6	61.6	60.5	60.9
Avg. Net. Oper. Heat Rate	9,945	9,634	9,633	9,663	9,643
Avg. Oper. Cost	1.499	1.593	1.707	1.849	1.716
Oil Fired Steam Units					
Schuylkill No. 1					
Planned Outage Factor %	7.5	5.8	5.8	5.8	5.8
Equiv. Avail. Factor %	54.8	63.5	65.7	67.3	65.5
Net Capacity Factor %	24.8	16.9	19.3	20.5	18.9
Avg. Net. Oper. Heat Rate	10,763	10,142	10,103	10,131	10,125
Avg. Oper. Cost	5.438	4.768	5.164	5.668	5.228

Description	Historical Average	Years Ending 6/30/87	6/30/88	6/30/89	Average
Eddystone No. 3					
Planned Outage Factor %	6.8	9.6	0.0	7.7	5.8
Equiv. Avail. Factor %	77.0	76.4	82.0	76.5	78.3
Net Capacity Factor %	21.0	12.4	15.5	14.9	14.3
Avg. Net. Oper. Heat Rate	13,216	13,255	12,932	12,879	13,009
Avg. Oper. Cost	6.613	6.110	6.521	7.079	6.599
Eddystone No. 4					
Planned Outage Factor %	9.4	9.6	0.0	7.7	5.8
Equiv. Avail. Factor %	77.5	78.1	88.7	80.8	82.5
Net Capacity Factor %	20.6	13.1	15.7	16.1	14.9
Avg. Net. Oper. Heat Rate	13,022	13,085	12,854	12,720	12,873
Avg. Oper. Cost	6.613	6.110	6.521	7.079	6.599
Cromby No. 2					
Planned Outage Factor %	3.2	42.2	7.7	7.7	19.2
Equiv. Avail. Factor %	77.5	45.8	81.8	72.1	66.6
Net Capacity Factor %	39.9	16.4	34.3	29.5	26.7
Avg. Net. Oper. Heat Rate	10,336	10,345	10,006	10,089	10,106
Avg. Oper. Cost	5.082	4.690	4.850	5.356	5.004
Delaware No. 7					
Planned Outage Factor %	9.9	5.8	5.8	5.8	5.8
Equiv. Avail. Factor %	68.8	77.5	77.6	79.4	78.2
Net Capacity Factor %	38.3	18.4	24.6	21.7	21.6
Avg. Net. Oper. Heat Rate	10,969	10,591	10,347	10,542	10,482
Avg. Oper. Cost	5.67	4.998	5.372	5.872	5.434
Delaware No. 8					
Planned Outage Factor %	9.9	5.8	5.8	5.8	5.8
Equiv. Avail. Factor %	64.9	71.0	71.7	71.8	71.5
Net Capacity Factor %	21.8	15.2	18.0	17.8	17.0
Avg. Net. Oper. Heat Rate	11,217	10,836	10,928	10,674	10,812
Avg. Oper. Cost	5.67	4.998	5.372	5.872	5.434

Combustion Turbine

Comparison Unit Data Report
Item 3(i)

Description	Historical Average	Future Test Year Prediction
Richmond		
Avg. Net Oper. Heat Rate	12,759	12,033
Avg. Net Fuel Cost	7.997	6.853
Croydon		
Avg. Net Oper. Heat Rate	12,425	10,993
Avg. Net Fuel Cost	7.361	6.363
Simple Cycle		
Avg. Net Oper. Heat Rate	15,285	14,023
Avg. Net Fuel Cost	9.602	8.158

Data Request (5) (1)

Purchased and Interchange Power
Historic and Projected Test Year

Supplemental Filing Data
Base Rate Case - Limerick 1

	Year ending 6-30-81		Year ending 6-30-82		Year ending 6-30-83		Year ending 6-30-84		Year ending 6-30-85		Year ending 6-30-87	
	MWH	$	MWH	$	MWH	$	MWH	$	MWH	$	MWH	$
Two Party Purchases	2,358,456	86,658,315	4,036,944	138,360,185	3,199,752	101,696,268	3,024,451	82,066,821	2,940,276	84,881,456	3,077,000	64,378,000
Two Party Sales	—	—	—	—	—	—	(55,525)	(1,467,805)	(82,870)	(2,184,093)	0	0
Interchange Purchases @ PSM	9,961,192	451,676,662	7,618,227	307,582,766	8,004,536	316,119,819	8,550,338	286,812,640	8,942,974	256,068,532	9,724,000	129,170,000
Interchange Sales @ PSM	(1,758,204)	(125,255,542)	(81,577)	(10,067,751)	(65,168)	(6,120,899)	(178,112)	(16,243,183)	(34,867)	(5,870,714)	(317,000)	(22,777,000)
Co-Generation Purchases *	684	33	508	31	188	7	176	6	8140	331	0	0
Borderline Interchange *	118,321	6,878	71,623	5,309	58,629	4,703	149,920	10,301	221,647	13,739	88,000	14,056
Schuylkill #3 Cogeneration	—	—	172,324	8,267,094	134,309	6,077,039	167,954	8,078,975	138,758	6,168,953	98,800	3,702,000

* KWH SALES

Notes for Data Requirement Tabulations

General

A - Data for Historical Filing Requirements is from NERC-GADS reports for PECO Units. 1980 and 1981 NERC Reports are for the full year. 1982 to present NERC Reports provide quarterly statistics. Therefore, Historical Statistics for years ending 6/30/81 and 6/30/82 are estimates based on full year data, for the remaining years the values reported are actual statistics for the years shown.

B - Since the NERC-GADS data for 1985 has not been processed, the data for the Hydro and CT units represents the last 5 years of statistics on a calendar year basis per agreement with the PUC Staff.

C - The Unit Derating Factor is not a calculated value in the NERC-GADS report and, therefore, the first two years could not be estimated, as explained in Note A.

D - All cost data is presented in ¢/KWH.

E - All heat rate information is in BTU/Net KWH.

F - The calculation, as determined by NERC, of equivalent forced outage hours on some combustion turbine units resulted in an equivalent forced outage rate greater than 100%.

G - Historical cost data on combustion turbine units is provided by accounting designator group.

H - Future test year projections of combustion turbine operating characteristics have been summarized into 3 groups:

1. Croydon - which includes all Croydon units.
2. Richmond - which includes all Richmond G.E. units.
3. Simple Cycle - which includes all other remaining CT units.

EDWARD C. FIRST, JR.
ROBERT H. GRISWOLD
MOSES K. ROSENBERG
ARTHUR L. BERGER
FRANCIS B. HAAS, JR.
G. THOMAS MILLER
DONALD R. WAISEL
RICHARD R. LEFEVER
J. THOMAS MENAKER
CLYDE W. McINTYRE
S. BERNE SMITH
ROD J. PERA
EDWARD W. ROTHMAN
ROBERT A. MILLS
W. JEFFRY JAMOUNEAU
HERBERT R. NURICK
DAVID E. LEHMAN
NORMAN I. WHITE
F. MURRAY BRYAN
RICHARD W. STEVENSON
WILLIAM A. CHESNUTT
HENRY R. MacNICHOLAS
WILLIAM M. YOUNG, JR.
ROBERT M. CHERRY

DAVID B. DISNEY
H. LEE ROUSSEL
MAURICE A. FRATER
C. GRAINGER BOWMAN
JOHN S. OYLER
DELANO M. LANTZ
HARVEY FREEDENBERG
EDWARD J. RIEHL
JASON S. SHAPIRO
ERIC L. BROSSMAN
ROBERT D. STETS
TERRY R. BOSSERT
MARY JANE FORBES
JEFFREY B. CLAY
DAVID M. KLEPPINGER
NEAL S. WEST
JESSIE L. SMITH
BRUCE A. FELDMAN
FRANKLIN A. MILES, JR.
MICHAEL A. DOCTROW
MICHAEL G. JARMAN
STEPHEN A. MOORE
DANA S. SCADUTO
BARBARA S. KAHOE

McNEES, WALLACE & NURICK
ATTORNEYS AT LAW
100 PINE STREET
P. O. BOX 1166
HARRISBURG, PA. 17108-1166
TELEPHONE (717) 232-8000

STERLING G. McNEES
1923-1959
DAVID M. WALLACE
1942-1967

RETIRED PARTNERS
HARRY H. FRANK
JAMES H. BOOSER
JAMES W. HAGAR
JAMES H. KING

OF COUNSEL
GILBERT NURICK
SAMUEL A. SCHRECKENGAUST, JR.
JEFFERSON C. BARNHART

December 30, 1985

Re: Pennsylvania Public Utility Commission, et al.,
v. Philadelphia Electric Company
Docket No. R-850152

RECEIVED
DEC 31 1985
SECRETARY'S OFFICE
Public Utility Commission

William E. Zeiter, Esquire
Morgan, Lewis & Bockius
2000 One Logan Square
Philadelphia, PA 19103

Dear Bill:

Enclosed please find Set No. 4 of the Philadelphia Area Industrial Energy Users Group, Item Nos. 68 through 70. As PECo completes its responses to these data requests, please forward copies to the undersigned and to:

Randall J. Falkenberg
Kennedy and Associates
Suite A-1220
1150 Hammond Drive
Atlanta, GA 30328

Jeffry Pollock
Drazen-Brubaker & Associates, Inc.
605 Old Ballas Road
P. O. Box 12710
St. Louis, MO 63141-0110

We appreciate your prompt attention to these matters.

Very truly yours,

McNEES, WALLACE & NURICK

By David M. Kleppinger
David M. Kleppinger

DMK/jf
Enclosures

cc: All Parties of Record (w/encl.)

CERTIFICATE OF SERVICE

Pennsylvania Public Utility Commission, et al., :
v. :
Philadelphia Electric Company : Docket No. R-850152
:

I hereby certify that I have served a copy of the foregoing document on all known parties of record to this proceeding, all by first class mail (unless otherwise indicated) properly addressed as follows:

Administrative Law Judge
Joseph P. Matuschak
PA Public Utility Commission
97 East Main Street
Uniontown, PA 15401

Marlane R. Chestnut, Asst. Counsel
Veronica A. Smith, Asst. Counsel
Daniel P. Delaney, Deputy Counsel
PA Public Utility Commission
Law Bureau
Room G-18 - North Office Bldg.
P. O. Box 3265
Harrisburg, PA 17120

Charles A. Smetak, Chief,
Bureau of Rates
PA Public Utility Commission
Room 200 - North Office Bldg.
P. O. Box 3265
Harrisburg, PA 17120

Irwin A. Popowsky, Esquire
David Wersan, Esquire
Scott J. Rubin, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

Reed Smith, Shaw & McClay
Attn: Franklin L. Kury, Esquire
300 North Second Street
P. O. Box 11844
Harrisburg, PA 17108

Southeastern Pennsylvania Transportation
Authority (SEPTA)
130 South 9th Street
Philadelphia, PA 19107

William E. Zeiter, Esquire
Counsel for Philadelphia Electric Compa
Morgan, Lewis & Bockius
Attn: Robert H. Young, Esquire
J. H. Clavert, Jr., Esquire
Frederick H. Knight, Esquire
David B. MacGregor, Esquire
2000 One Logan Square
Philadelphia, PA 19101

Edward G. Bauer, Jr., Esquire
Vice President and General Counsel
Philadelphia Electric Company
2301 Market Street
Philadelphia, PA 19101

Janet Parrish, Esquire
Community Legal Services Energy Project
3638 North Broad Street
Philadelphia, PA 19140

Zori G. Ferkin, Chief Counsel
Roger E. Clark, Esquire
Governor's Energy Council
300 N. Second Street - 11th Floor
P. O. Box 8010
Harrisburg, PA 17101

Reed, Smith, Shaw & McClay
Attn: Michael L. Browne, Esquire
J. Tomlinson Fort, Esquire
J. Thomas Morris, Esquire
1600 Avenue of the Arts Building
Broad & Chestnut Streets
Philadelphia, PA 19107

National Railroad Passenger Corporation
1617 John F. Kennedy Boulevard
Philadelphia, PA 19103

Sutherland, Asbill & Brennan
Attn: Earle H. O'Donnell, Esquire
Merrill L. Kramer, Esquire
1666 K Street, N.W.
Suite 800
Washington, DC 20006-2803

Occidental Chemical Corporation
Attn: Robert D. Luss, Esquire
Group Counsel
P. O. Box 699
Armand Hammer Boulevard
Pottstown, PA 19464

Duane, Morris & Heckscher
Attn: Scott C. Penwell, Esquire
203 Pine Street
P. O. Box 1003
Harrisburg, PA 17108-1003

Occidental Chemical Corporation
Attn: Anthony G. Tummarello, Director of Energy
P. O. Box 4020
River Park
Darien, CT 06820

Widoff Reager Selkowitz & Adler, PC
Attn: Mark P. Widoff, Esquire
129 State Street
Harrisburg, PA 17101

General Services Administration
Attn: Michael J. Ettner, Esquire
Office of General Counsel
Washington, DC 20405

David M. Kleppinger

Dated this 30th day of DECEMBER, 1985

at Harrisburg, PA

PHILADELPHIA ELECTRIC COMPANY

Pennsylvania PUC Docket No. R-850152

Data Requests of
Philadelphia Area Industrial Energy Users' Group
Addressed to Philadelphia Electric Company
Set No. 4

Item No.	Description
68.	With respect to PECO's response to PAIEUG-1-20, please provide a schedule showing the projected generation (by fuel type) and purchase power energy mix both in gigawatthours and in percent of total net energy for load from 1985 through 1995.
69.	With respect to PECO's response to PAIEUG-1-21, please provide a copy of the appropriate section from the Environmental Report--Construction Permit Phase filed with the Nuclear Regulatory Commission (or its predecessors) which decribes the alternatives to building Limerick Unit No. 1.
70.	With respect to PECO's response to PAIEUG-1-23, please provide a copy of the official peak load forecast coinciding with each official delay identified in PECO's Statements 1 and 3. Also provide a copy of Schedule 7 referred to in the earlier response.

DOCKETED
DOCKET
JAN 02 1986

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P. O. BOX 3265, HARRISBURG, Pa. 17120

December 31, 1985

IN REPLY PLEASE
REFER TO OUR FILE

RECEIVED
DEC 31 1985
SECRETARY'S OFFICE
PUBLIC UTILITY COMMISSION

The Honorable Jerry Rich, Secretary
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17120

RE: Pennsylvania Public Utility Commission
v.
Philadelphia Electric Company
Docket No. R-850152

Dear Secretary Rich:

Recently the Philadelphia Electric Company submitted a Petition for Commission Review and Answer A Material Question in the above-captioned case. The current Commission rules allow only seven days for the preparation of a brief supporting or opposing the petition. 52 Pa. Code §5.302. Due to the holiday season, I am requesting an extension of time which will permit all parties to file their briefs on January 6, 1986. During recent phone conversations, Mr. Stuart W. Fraser, Esquire, representing Philadelphia Electric Company and Mr. David Wersan, Assistant Consumer Advocate, have agreed to the extension of time. To the best of my understanding, these parties are the only ones actively interested in submitting briefs on the issue.

I appreciate your cooperation in this matter. A copy of this letter is being sent to all parties of record.

Sincerely yours,

Daniel P. Delaney
Deputy Chief Counsel

cc: Parties of Record
Cheryl Walker Davis, Chief
Office of Special Assistants

DOCKETED
JAN2 1986

MORGAN, LEWIS & BOCKIUS
COUNSELORS AT LAW
2000 ONE LOGAN SQUARE
PHILADELPHIA, PENNSYLVANIA 19103
TELEPHONE: (215) 963-5000
CABLE ADDRESS: MORLEBOCK
TELEX: 83-1315

WASHINGTON
NEW YORK
LOS ANGELES

MIAMI
HARRISBURG
LONDON

ANTHONY C. DECUSATIS
DIAL DIRECT (215) 963-5411

December 31, 1985

RECEIVED
DEC 31 1985
SECRETARY'S OFFICE
Public Utility Commission

Jerry Rich, Secretary
Pennsylvania Public Utility
Commission
North Office Building
Commonwealth & North Streets
P. O. Box 3265
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
Philadelphia Electric Company
Docket No. R-850152

Dear Secretary Rich:

On December 30, 1985, additional direct testimony and exhibits were filed on behalf of Philadelphia Electric Company in the above-captioned matter which included Statement 30 (Direct Testimony of Joseph W. Gallagher). Schedule 2 was not attached to the copies of Statement 30 filed yesterday. Therefore, there is enclosed herewith for filing three copies of Statement 30 with copies of accompanying Schedules 1 and 2 attached.

DOCUMENT
FOLDER

Very truly yours,

Anthony C. DeCusatis

Anthony C. DeCusatis

ACD:vo
ENC:
cc: Honorable Joseph P. Matuschak
All Active Parties

RECEIVED
DEC 31 1985
SECRETARY'S OFFICE
Public Utility Commission

PECO Statement No. 30
Docket No. R-850152

TESTIMONY OF JOSEPH W. GALLAGHER

Q: Please state your name and business address.

A: Joseph W. Gallagher, 2301 Market St., Philadelphia, PA.

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

A: I am employed by the Philadelphia Electric Company and, since January 1984, I have served as Manager of the Engineering and Research Department. For six years prior, I was Manager of the Electric Production Department.

DOCUMENT FOLDER

Q: What is your educational background?

A: I graduated from Villanova University in 1949 with a degree of Bachelor of Electrical Engineering. In 1967, I completed the Executive Development Program at Cornell University and have taken graduate courses at Northwestern and Drexel Universities.

DOCKETED
JAN 7 - 1986

Q: What are your professional affiliations?

A: I am a licensed professional engineer in Pennsylvania, License #02358E. I was a member of the Operating Committee of the Pennsylvania, New Jersey, Maryland ("PJM") Interconnection for eleven years and was a member of the North American Power Systems Interconnection Committee for four years. I have served on the U.S.-U.S.S.R. Committee on Power System Planning and Operation since 1974 and also

serve on the Prime Movers Committee of the Edison Electric Institute, which is concerned with power generation matters. I am also a senior member of the Institute of Electrical and Electronics Engineers and have served on several technical committees of that organization.

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

A: I started with Philadelphia Electric in 1950 as an electrical engineer in the System Planning Division where I worked for approximately 12 years. My duties included planning of the distribution system and the generation and transmission systems and, later, supervision of the long-range generation and transmission branch. After that, I was assigned to the General Administration Department as a staff engineer for about six and one-half years. I was promoted to Assistant Superintendent of the System Operation Division in the Electric Production Department where I worked for five years and was then promoted to Superintendent in the same division for three years. During that time, I was responsible for scheduling production at Philadelphia Electric plants, assuring that they were on-line when needed, directing the load at which the plants were being operated, coordinating plant maintenance and releasing equipment for maintenance, directing the switching and blocking on the transmission system; monitoring transmission

line loadings, coordinating generation and transmission outages, and managing service restoration. I served as General Superintendent of the Maintenance Division for one year before being promoted to Manager of the Electric Production Department in April, 1978. My responsibilities, as General Superintendent of Maintenance, included management of the maintenance program of all generating stations, substations, and steam heating system facilities on the Philadelphia Electric Company system.

Q: Please briefly describe the Engineering and Research Department and your responsibilities as Manager of that Department.

A: The Engineering and Research Department is responsible for the planning, engineering, design and construction of all new facilities of the Philadelphia Electric Company. It is responsible for capital modifications of all facilities, load estimating, system planning, and research projects, also. As Manager of the Engineering and Research Department, I administer all of the functions of the Department, subject to the direction and supervision of the Vice President, Engineering and Research. In addition, I review the budgets and cost control systems for all capital work at all facilities, including those partially owned by Philadelphia Electric, but not operated by the Company.

Q: Previously you indicated that, prior to January, 1984, you were the manager of the Electric Production Department. Please briefly describe the Electric Production Department and the responsibilities you had in your prior position as Manager of that Department.

A: The Electric Production Department operates and maintains all of the electrical production facilities operated by Philadelphia Electric, including the Company's nuclear, coal, oil and hydroelectric facilities. It also operates and maintains the Company's steam heating supply stations. The Department is responsible for maintenance work on all generation and supply equipment under Philadelphia Electric's control and coordinates the Company's operations with the PJM Interconnection. As Manager of the Electric Production Department, I administered all of the functions of the Department, subject to the direction and supervision of the Vice President, Electric Production. In addition, I reviewed the operations, budgets, and cost control systems for the electrical production facilities including those partially owned by Philadelphia Electric, but not operated by the Company. These include the Salem nuclear plant, which is operated by Public Service Electric & Gas Company and two coal-fired generating stations (Keystone and Conemaugh) operated by Pennsylvania Electric Company.

Thus, in my positions as the former Manager of the Electric Production Department and now as Manager of the Engineering and Research Department I have had responsibility for, and exercised oversight of, the planning, engineering and implementation of both capital modifications and maintenance work. As I will explain below, these two categories -- capital modifications and maintenance work -- represent the classifications into which all major improvement projects at generating stations are divided for cost approval and implementation purposes.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain improvements Philadelphia Electric Company has made or intends to make in the near future to its baseload generating units to enhance their performance. This information is provided to comply with the following data requirements which are contained in Appendix B to the Pennsylvania Public Utility Commission's Order entered October 30, 1985 at Docket Nos. P-830453, M-840375 and M-FACE8408:

> "The following information and data shall be supplied by the Company ...
>
> (4) <u>Generating Unit Performance Improvements</u>
>
> (i) A report detailing all Company efforts designed to improve system generating efficiency ..."

The Order further explained this data requirement by stating that the information to be provided should focus upon

"Prudent and projected generating unit performance improvements planned or anticipated by the Company."

I also explain major procedure-oriented and personnel-oriented changes and programs as well as capital and maintenance improvements that can have a positive effect on baseload generating performance. I also describe generally the processes and procedures employed by the Company to identify, authorize and implement capital modifications and maintenance work.

I have provided information principally with regard to baseload units. These consist of nuclear units (Peach Bottom 2 and 3 and Salem 1 and 2), the Philadelphia-Area coal-fired units (Eddystone 1 and 2 and Cromby 1), and the mine-mouth coal-fired units (Keystone 1 and 2 and Conemaugh 1 and 2). I should mention that, while the Philadelphia-Area coal-fired units have been categorized as baseload units, they are used by the Company for load-following at times.

Of course, the Company also has oil-fired units, combustion turbines and hydroelectric capacity. However, I have presented information principally for nuclear and coal-fired baseload units because, due to the duration of their operation throughout a year and relatively lower energy costs, "performance improvements" in these units generally have a greater effect on system energy costs.

For purposes of the information I have provided, I interpreted the criteria "system generating efficiency" and "unit performance improvements" as encompassing, in the case of nuclear units, unit availability and, in the case of coal-fired units, unit availability and thermal efficiency. By thermal efficiency, I mean net unit output relative to the fuel input.

Q: Explain how capital modifications and needed maintenance at generating stations is identified, authorized and implemented.

A: As I previously described, the Company's Electric Production Department is responsible for the operation and maintenance of all the Company-operated generating facilities. The Superintendent and Assistant Superintendent at each station, who are typically referred to as "Station Management", are members of that Department. Station Management originates requests for investigation of systems or components that either have failed or are exhibiting what station personnel consider to be deteriorated or unsatisfactory performance. Such investigations are conducted by the Engineering and Research Department's Mechanical or Electrical Engineering Divisions, with input from station personnel or other divisions of the Electric Production Department, as required or deemed desirable. Such investigation is directed to establish the probable cause of the identified failure or

unsatisfactory performance, to develop the necessary plan for fixing or improving the system or component studied, to estimate the costs to implement the fix, to make necessary cost-benefit analyses to determine if implementing the design fix is cost-justified and will provide an overall "economic" benefit, and to make a recommendation to Station Management.

If the recommendation is to proceed with the work identified as necessary and cost-justified, Station Management makes a request for authorization to expend funds for the project. If the work entails a capital modification, a Capital Authorization or "CA" is requested. If the necessary work represents maintenance, an Expense Authorization or "EA" is requested. PECO management reviews and approves the requested CAs and EAs, the expenditures for which must be integrated into PECO's overall capital and operating budgets.

After a CA or EA is approved, implementation requires completion of final engineering, scheduling (work that can be done only when a unit is shut down must be fit into the schedule for planned outages), procurement of necessary materials, and preparation of specifications and requests for bids or proposals if outside contractors are to be used.

Work authorized by a CA is implemented by the Engineering and Research Department's Construction Division,

and work authorized by an EA is implemented by the Maintenance Division of the Electric Production Department. However, engineering design and technical supervision is provided, in both cases, by the Engineering and Research Department.

Q: What is the Company's participation in the process of authorizing capital and maintenance work at jointly-owned plants that are operated by a joint-owner other than PECO?

A: For jointly-owned plants operated by others, PECO participates in the work review and approval process at the level of the owners' groups, consisting of representatives of each utility having an ownership share in the plant. The operating utilities have procedures similar to PECO's for identifying, analyzing, cost-justifying and approving capital and maintenance work. The strategic decisions for major capital or maintenance programs are submitted to the owners' group for review and approval.

Q: Please describe the information you are submitting in response to the data requirements of the Commission's October 30, 1985 Order.

A: The information is set forth in Schedules 1 and 2 attached to this Statement. Each Schedule corresponds to the categorization of work projects I identified before. That is, Schedule 1 lists capital modifications and Schedule 2 lists maintenance projects. Additionally, Schedule 2

describes personnel-oriented and procedure-oriented changes that are intended or expected to have a beneficial effect on unit performance.

Q: Please refer to Schedule 1 and explain what it shows.

A: Schedule 1 consists of five tables, each containing information about one or more units, as follows:

Table 1	Eddystone 1 and 2
Table 2	Cromby 1
Table 3	Peach Bottom 2 and 3
Table 4	Salem 1 and 2
Table 5	Keystone 1 and 2 and Conemaugh 1 and 2

Each Table shows, for the units it comprehends, capital modifications that will have a positive impact on unit performance. The modifications have been broken out among those completed within the last three years and those projected for substantial completion within the three-year period ending in 1988. Some of the projected work is already in progress.

The first column identifies the project, the second column shows the approximate cost, the third column indicates the area of performance anticipated to be enhanced (availability and/or efficiency), and the last column provides additional information explaining the need for or likely benefit of the work.

I should note that, because the number of modifications for each unit is voluminous, I have shown only those that exceeded or are anticipated to exceed $1 million.

Some of the projects listed were necessitated for environmental, safety-related, or regulatory compliance. However, the work was included on the schedule because, if not done, the performance of the unit would have been adversely affected. Thus, for example, RHR and recirculation pipe replacement at Peach Bottom 2 was necessitated by safety-related concerns associated with the generic problem of Intergranular Stress Conosion Cracking in large-bore piping of Boiling Water Reactors, which was present at Peach Bottom. By replacing the piping with non-susceptible material and by using longer spool lengths -- thereby reducing the number of welds -- a potential future reduction in inspections could be expected, which should reduce outage time, reduce the risk of shut-downs due to IGSCC-related problems, and exert a positive effect on future availability. Similarly, changes in SO2 scrubbers at the Philadelphia Area Coal plants have the potential to reduce the duration of shut-downs to comply with environmental standards.

Q: Please refer to Schedule 2 and explain what it shows.

A: Schedule 2 consists of two parts. Part I contains a description of major maintenance work in progress or scheduled for completion within approximately three years that is expected to have a positive effect on unit performance. In lieu of itemization of work packages, to

which the maintenance work does not readily lend itself, a brief narrative description of the work to be performed on a system or component is provided.

Part II contains, also, a brief description of major procedure-oriented and personnel-oriented programs implemented by the Company that are expected to enhance or avoid deterioration of unit performance by reducing outage time or that are expected to reduce the cost of operation and maintenance by permitting needed work to be done in a more time and/or cost efficient manner.

Q. Please provide an overview of significant planned improvements affecting performance at the Company's coal and nuclear plants which are intended to address major contributors to unit unavailability.

A. For Peach Bottom, such significant planned improvements include refueling platform replacements and increasing the capacity of the spent fuel rack -- which should improve refueling performance, replacing the feedwater heater, replacing the low pressure turbine rotors on Peach Bottom 3 (rotors in Peach Bottom 2 were replaced during the outage which ended in July, 1985), and replacement of recirculation and RHR piping in Peach Bottom 3. More detail as to the effect of these improvements is set forth in Schedule 1, Table 3.

For Salem, such significant planned improvements include various pump improvements and replacements, heat exchangers' modifications, and major control and instrumentation modifications, as detailed in Schedule 1, Table 4.

For the Philadelphia-area coal plants such significant planned improvements include, at Cromby 1, replacing the low pressure rotor, modifications to the fly ash disposal system, and installation of micro-processor-based controls, and, at Eddystone, replacing the feedwater heaters at Unit 2, completion of the comprehensive boiler rehabilitation program at Unit 2, installation of micro-processor-based controls at both units, and implementation of computer analysis to identify availability impacting problems with the SO2 scrubbers on both units. More detail as to these items is set forth in Schedule 1, Tables 1 and 2.

For the mine-month coal plants, such significant improvements include, at Keystone, replacing economizers, balanced draft conversion, and replacing low pressure feedwater heaters, and, at Conenaugh, replacing the low pressure and high pressure feedwater heaters, replacing air preheater coils, and obtaining spare low and intermediate pressure turbine rotors. In addition, major replacements and modifications of steam generator components (casings, ductwork and pressure vessels) have been in progress and are

continuing. These and additional items are explained in Table 1, Schedule 5.

Q. In addition to the specific equipment-based projects you have described, please describe PECO's preventive maintenance program.

A. PECO has in place an extensive preventive maintenance program applicable to all of its generating stations. For example, during each legally-mandated boiler inspection, the boiler is extensively inspected both visually and by non-destructive testing to detect and correct developing problems that could result in forced outages or decreased capacity. Each major steam turbine-generator is totally inspected over a six-year cycle, on a component-per-year basis. All unit generators, major electric motors, and transformers are inspected and subjected to electrical testing on a periodic basis to detect incipient failures. Periodic inspections and overhauls of all major auxiliary systems are made on schedules reflecting the Company's experience in maintaining central generating station equipment. The goal is to reduce the forced outage rate to the maximum feasible and cost-effective extent, considering resource limitations, and to reduce scheduled outages to a minimum cost-effective duration and frequency.

Q. Explain the general principles and criteria that guide PECO's approach to making "unit performance improvements".

A. PECO's general approach is to implement practicable capital or maintenance projects and programs that, based on appropriate analysis and engineering judgment, are reasonably projected to result in overall economic benefit. The pursuit solely of the highest standard of unit performance to the exclusion of other concerns can produce uneconomic results. That is, the capital and maintenance costs incurred to achieve an incremental increase in operating performance can exceed the marginal reduction in energy costs they might produce. In short, work to be done solely to achieve increased unit performance must be cost-justified on the basis of total costs.

These principles are taken into account by PECO in the work authorization procedures I explained before. Specifically work -- other than that mandated by regulatory requirements or health and safety concerns -- is analyzed on a cost benefit basis before expenditures are authorized. The cost-benefit analysis can be more or less formal or sophisticated depending upon the nature, scope and total cost of the work. In some cases, the cost-benefit is clearly justified or unjustified without substantial, written analyses.

Q. Can you explain briefly the quantifiable effects on unit performance of unit improvements and modifications.

A. The effects on total unit performance are difficult to quantify, because unit performance is a function of the dynamic interaction of numerous complex engineering systems. There is one important factor to be remembered, however. Improvements in the performance of a given system or component are not translated into improvements in total unit performance of equal magnitude. Thus, if problems in a given system or component contributed 2 percentage points to the unit's total forced outage rate, correcting those problems will not result in a 2 percentage point reduction in the forced outage rate. The improvement in unit forced outage rate is, generally, less than the improvement in the system's or component's performance. Moreover, as a unit ages and new problems arise, no absolute improvement in performance from past capital modifications and maintenance activities may occur. Rather, capital modifications and maintenance achieve a continuation of existing performance levels or of levels above those that would otherwise be obtained absent those efforts.

Q. Does this conclude your statement?

A. Yes, it does.

SCHEDULE 1

TABLE 1

EDDYSTONE UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Rotor stress indicators		A	Guide to operator to prevent misoperation that ultimately would result in shortened turbine life
Cold reheat water induction protection system (Unit 2)		A	same as above
Chlorine injection modifications		A/E	Prevents organic contamination of condensor--thus improving efficiency--while complying with stricter environmental regulations
Electrostatic precipitator rappers		A/E	Replace and upgrade rappers; reduces particulate scrubbing
Water discharge system modifications		A/E	Improvements to turbine bypass reduces start-up time, improve availability and reduces start-up fuel
Auxilliary steam back-up		A/E	Improvements that shorten start-up time, improve availability and reduce start-up fuel
Fire protection modifications		A	Localizes and minimizes damage in the event of a fire, thereb reducing possibility of long forced outage due to fire and resulting damage
SO_2/particulate scrubbers	147,430	A	The only alternatives to compl with the Clean Air Act were to retire the unit or convert the units to oil. Installation of scrubbers was the most economical choice to retain that capacity.

TABLE 1

EDDYSTONE UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Replace main steam piping (Unit 1)	8,575	A	Piping was at the end of life; in order to retain this unit's capacity, piping had to be replaced.
Coal pile runoff system	1,650	A	Due to environment law requirements, if this system were not added, the plant would have to be retired or converted to oil.
Turbine stop and control valves	6,420	A	Same as MSP replacement
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace superheater outlet headers (Unit 1)	4,110	A	Material at end of life; to retain this capacity, replacement required.
Develop and implement program to assess high pressure piping integrity		A	To identify possible incipient problems so that effective planning can be developed and repair or replacement coordinated with scheduled outages
Wastewater treatment modifications	1,046	A	To avoid breakdowns that result in environmental violations requiring shutdowns
Feedwater, steam temperature, CC, PD and H.P. boilerfeed pump controls	1,790	A/E	Initial phase of long-term program to upgrade major control systems using microprocessor distributed system technology. To maintain steam pressure and temperature within design parameters. Shortens start-up time and improves thermal performance

TABLE 1

EDDYSTONE UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Water induction protection (Units 1 and 2)		A	Expanded application of water induction protection explained before
Soot blower control panel replacement		A/E	Replacement and upgrade to allow closer control of steam temperature
ATC (combustion air) drive and control replacement		A/E	Replace and upgrade. Provides more efficient burning of fuel by giving operator control of combustion air
Auxilliary boilers (convert from No. 6 fuel oil to gas firing)	1,500	A/E	Increases availability (because lower maintenance) and improves efficiency
Replace igniters (Units 1 and 2)	1,000	A/E	Reduces start-up time, reduces start-up fuel, increases availability
Replace air tempering coils		A/E	Improves thermal performance
Replace feedwater heaters (Unit 2)	2,135	A/E	Recoup availability and thermal efficiency lost due to tube failures
Air dryers		A	Reduces moisture in compressed air-powered controls; avoids freeze-up
Vibration monitoring		A	Upgrade monitoring of rotating equipment to avoid in-service failures

TABLE 2

CROMBY UNIT 1

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
SO_2/particulate scrubbers	77,032	A	(see explanation of similar item in Table 1)
Replace ignitors		A/E	(see explanation of similar item in Table 1)
Replace economizer		A/E	Improves availability; avoids forced outage due to tube failures
Bag house by-pass duct		A	Allows operation while bag-house is out of service
Replace No. 4 feedwater heater		A/E	(see explanation of similar item in Table 1)
Feedwater, steam temperature, CC controls		A/E	(see explanation of similar item in Table 1)
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Chlorine injection system		A/E	(see explanation of similar item in Table 1)
Demineralizer regeneration pump suction modifications		A	Pump modification to reduce in-service failures
Fire protection modifications		A	(see explanation of similar item in Table 1)
Coal pile run-off system		A	(see explanation of similar item in Table 1)
Purchase of replacement L.P. rotor		A/E	Permits replacement during scheduled outage; updated blade design

TABLE 3

PEACH BOTTOM UNITS 2 AND 3

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Off-gas system improvements	6,526	A	Installation of separators, drains and vents to improve moisture removal; increase reliability and reduce maintenance.
Rod-waste storage facility	6,100	A	Increase storage.
Recombiner upgrade		A	Eliminated need for pressurized hold-up and compression; increases reliability and decreases maintenance.
Main steam drain valves		A	Facilitates moisture removal from main stream lines; reduces risk of damage to turbine.
Plant simulator	1,800	A	Used for operator training; increases efficiency of operation and has potential to reduce down-time due to operator error.
Replace recirculation and RHR piping (Unit 2)	31,100	A	Replacement with nonsusceptible material and longer spool pieces; reduces ISI and future IGSCC problems.
Replace safe ends (Unit 2)	4,840	A	Replacement with nonsusceptible material; reduces future IGSCC problems.

TABLE 3

PEACH BOTTOM UNITS 2 AND 3

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace L.P. turbine rotors (Unit 3)	2,970	A	Improve future reliability, reduce maintenance; restore performance capability.
Reactor feed pumpts recirculation valves		A	
Refueling platform modifications		A	
Increase capacity of spent fuel racts	3,830	A	Increases number of cycles of operation with existing spent fuel pool.
Install new recirculation and RHR piping (Unit 3)	30,170	A	(See the explanation of similar item for Unit 2).
Replace L.P. turbine rotors (Unit 2)	2,150	A	(See the explanation of similar item for Unit 3).
Replace feedwater heaters		A	(See explanation of similar item in Table).
Control room and instrumentation modifications		A	Partially NRC-required; increases operating efficiency.

TABLE 4

SALEM UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E)= Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Rewind generator (Unit 1)	2,252	A	Generator failed; rewind increases reliability and availability.
Replace generator (Unit 2)	10,350	A	Generator failed, replacement necessary to restore unit availability; increases reliability.
Upgrade moisture separator reheater shells	2,428	A	Improves moisture removal; reduces risk of damage to turbine.
Condensate pump mod. (Unit 2)	1,313	A	Increase reliability, reduces maintenance and increases cycle efficiency.
Retube component cooling heat exchanger		A	Experiencing numerous tube failures; retubing increases reliability and availability.
Upgrade circulating water screen wash.		A	Improves operation and reduces maintenance.
Upgrade H.P. feedwater heater internals		A	Experiencing failures and degraded performance; internals upgrade increases reliability and performance.

TABLE 4

SALEM UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
Reactor coolant pump motor resistance rings		A	Improve availability, reduce maintenance.
Replace turbine by-pass steam valves		A	Reduces start-up time; improves availability.
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace moisture separator tube bundles	5,473	A	(See the explanation for MSR shell replacement).
Replace RHR sump pumps		A	Old pumps were experiencing high level of failures affecting availability.
Upgrade circulating water pump leaving lubrication pump		A	Improved bearing cooling capability which had become a high maintenance item.
Reactor vessel head quick disconnect tensioner		A	Facilitates head removal; reduces outage time.
Replace service water strainer		A	Existing strainer experiencing high maintenance and poor availability due to corrosion.

TABLE 4

SALEM UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Replace chiller condensers		A	Existing condensers experiencin high rate of tube failures; replaces increases reliability and performance
Replace primary system flow transmitters		A	Existing transmitters were high maintenance items and spare parts not available; replacemen increases reliability and performance.
Replace turbine area sump pumps		A	Old pumps experiencing failures affecting availability.
Upgrade plant simulator		A	(See explanation of similar item in Table 3).
Upgrade circulating water pump internals		A	High maintenance and effect on availability; upgrade increases reliability.
Replace service water piping to component cooling heat exchanger		A	High maintenance item -- leaks and failures -- operating availability; upgrade increases reliability.
Turbine-generator suspension instrumentation		A	Temperature and vibration monitoring; identifies incipien problems; avoids failures, reduces trips during start-up.

TABLE 5

KEYSTONE UNITS 1 AND 2
CONEMAUGH UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
COMPLETED DURING LAST 3 YEARS			
(Keystone)			
Turbine water induction protection modifications		A	Guide to operator to prevent misoperation that ultimately could result in shortened turbine life
Develop East Valley ash and coal refuse disposal site	1,520	A	Adequate, environmentally-approved waste disposal site required for continued operation
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
(Keystone)			
Replace economizers	4,000	A/E	(see explanation of similar item in Table 2)
Convert boilers to balanced draft	10,745	A/E	Increase availability by reducing casing leaks and hot spots
Replace station computers	1,880	E	To monitor operating parameters and highlight losses that can be corrected
Develop additional ash disposal sites		A	(see similar item explained above)
Electrostatic precipator modification		E	Improve collecting efficiency; avoids load reductions due to air pollution violations
Replace L.P. feedwater heaters		A/E	(see explanation of similar item in Table 1)
Purchase spare boiler circulating pump		A	Long lead time item; purchased in advance for orderly integration of repair/replacement in scheduled outage and less downtime in event of in-service failure

TABLE 5

KEYSTONE UNITS 1 AND 2
CONEMAUGH UNITS 1 AND 2

TITLE/DESCRIPTION OF MODIFICATION	COST (1000s) ($)	Reason and Effect on Performance A = Availability E = Efficiency	Notes and Discussion
PROJECTED TO BE COMPLETED WITHIN 3 YEARS			
Wastewater treatment system improvements		A	(see explanation of similar item in Table 1)
Purchase spare boiler feed pump coupling elements		A	Reduce risk of extended outage due to in-service failure or inspection that discovers problem. Long lead-time for procurement.
(Conemaugh)			
Replace H.P. and L.P. Feedwater heaters	1,312	A/E	(see explanation of similar item in Table 1)
Replace station computers	1,852	E	(see explanation of similar item for Keystone)
Develop additional ash disposal sites	1,140	A	(see explanation of similar item for Keystone)
Electrostatic precipitator gas flow improvements		A	(see explanation of similar item for Keystone)
Purchase spare boiler circulating pump		A	(see explanation for similar item for Keystone)
Heat rate monitoring equipment		E	Adjunct to computers and extension of their capabilities

SCHEDULE 2

SCHEDULE 2

I. EQUIPMENT-CENTERED EFFORTS

Rehabilitation of Eddystone 1 and 2 steam generators' pressure vessel parts is being pursued to improve availability. The program on Unit 1 was completed earlier than planned because of the opportunity afforded by the forced outage for replacing main steam piping in 1983-84. The Unit 2 program is scheduled for completion in 1989.

In addition to the rehabilitation programs described above, a comprehensive program was initiated in 1984, in cooperation with the original equipment manufacturer, to study and improve the availability and thermal efficiency of the Eddystone Unit 1 steam generator and auxilliaries. This program includes a review of operating practices and procedures. Results obtained from the Unit 1 program will be applied to Unit 2. Resources permitting, the program is anticipated to be completed by 1989.

A proposal is being considered to apply UNIRAM (computer based) analysis to identify availability problems in Eddystone Unit 1 and 2 scrubbers. A similar program was completed on Cromby Unit 1 scrubber in 1985. Once the problems are identified, a cost-benefit analysis will be performed to determine if and what action should be taken.

Redesign of the boiler feed pump seals on Eddystone Units 1 and 2 is continuing in cooperation with the original equipment manufacturer to minimize forced reductions and to incorporate design improvements growing out of experience.

Major replacements and modifications have been in process since 1982 and are continuing for Conemaugh Units 1 and 2 and Keystone Units 1 and 2 steam generators including castings, ductwork and pressure vessels, intended to improve availability. This work is being done pursuant to a major study performed by a consulting engineering firm to identify areas for improvement. Allied work on controls is also scheduled for the Conemaugh units.

Development and implementation of a comprehensive quality assurance manual and program is in progress at Keystone and Conemaugh. This is expected to result in assurance of high quality workmanship and better reliability of equipment which supports the objectives of better station performance.

Begun in 1985, improvements continue to core/fuel element mechanical/nuclear design leading to economies in fuel cost and increased availability at Peach Bottom. Improved core monitoring is being implemented as well as proposed changes in control rod systems, which are expected to have a positive effect on availability and capacity factor. All these improvements are scheduled in stages, with final completion anticipated in the 1990-1991 time frame. (Additional detail can be provided).

New maintenance tools and equipment are being purchased to improve productivity. Increased use of NDE is designed to improve availability of units through early detection of incipient failures.

II. PERSONNEL-CENTERED EFFORTS

Training of operating and maintenance personnel for Eddystone, Cromby, Keystone and Conemaugh has been upgraded and intensified. An example is the expansion of the training program for fossil and hydro plant operators begun in 1985. The improved and heightened training is designed to reduce operating errors and improve maintenance productivity, leading to increased unit availability and thermal performance.

At PECO, new maintenance mechanic training facilities have been in operation for approximately four years. Improved productivity is expected to result, and the effects should be evident in the near future. PECO is currently undergoing self-evaluation for IMPO accreditation.

III. PROCEDURAL-CENTERED EFFORTS

Planning, scheduling and management of unit outages and routine maintenance, including refueling outages at Peach Bottom and Salem, is being improved by increased use of

computer-aided programs, such as CHAMPS (a preventive maintenance program) and MOMS (Maintenance outage managment system) to schedule resources, PICOM (project information and cost management) to track costs and PREMIS (project resource evaluation and management information system) to minimize outage length and levelize manpower requirements.. Maintenance planning and scheduling is assisted by MAINPLAN, a computer program designed to optimize resource needs while minimizing outage costs. All the programs utilize procedures and techniques designed to improve site management of outages. The outage planning and management reinforcement began at Peach Bottom in 1980, and 1981 at Eddystone.

The program for tracking and monitoring plant performance and equipment degradation is being intensified at Peach Bottom and increasing emphasis is being placed upon maintaining and improving thermal efficiency.

MORGAN, LEWIS & BOCKIUS
COUNSELORS AT LAW
2000 ONE LOGAN SQUARE
PHILADELPHIA, PENNSYLVANIA 19103
TELEPHONE: (215) 963-5000
CABLE ADDRESS: MORLEBOCK
TELEX: 83-1315

WASHINGTON
NEW YORK
LOS ANGELES

MIAMI
HARRISBURG
LONDON

FREDERICK H. KNIGHT, 3RD
DIAL DIRECT (215) 963-5377

December 31, 1985

RECEIVED
DEC 31 1985
SECRETARY'S OFFICE
Public Utility Commission

Jerry Rich, Secretary
Pennsylvania Public Utility Commission
North Office Building
Commonwealth & North Streets
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v. Philadelphia Electric Company
Docket No. R-850152

Dear Secretary Rich:

Enclosed for filing with the Commission are the original and two copies of Transcript Corrections of Philadelphia Electric Company in the above-captioned proceeding for hearings held on December 16-17, 1985.

This document is being filed pursuant to 52 Pa. Code §1.11 by use of a U.S. Postal Service Form 3817 Certificate of mailing.

I hereby certify that I have today served copies of this document on the Administrative Law Judge and all Active Parties to this proceeding.

Sincerely,

Frederick H. Knight

ddq
Enclosure

cc: The Honorable Joseph Matuschak
All Active Parties

DOCUMENT FOLDER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

RECEIVED
DEC 31 1985
SECRETARY'S OFFICE
Public Utility Commission

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

TRANSCRIPT CORRECTIONS
OF
PHILADELPHIA ELECTRIC COMPANY
FOR HEARINGS ON DECEMBER 16-17, 1985

DOCKETED
JAN 7 - 1986

DOCUMENT
FOLDER

December 31, 1985

PECO Transcript Corrections for the hearings held on December 16, 1985

Page	Line	Correction
739	5	Change "sited" to "side of the"
739	18	Change "Buck" to "Bupp"
739	22	Change "Buck" to "Bupp"
740	9	Change "correctly" to "directly"
771(j24)	17	(Judge's transcript for 12/16/85) Change "optional" to "optimal"
776	10	Change "Chier" to "Chief"
841	8	Insert "desired" before "reserve"
848		
850	4	Strike "and so on"
853	20	Change "the" to "if"
"	"	Change "facility's" to "facility is"
853	21	Change "delay" to "delayed"
853	22	Change "and" to "in"
885	21	Change "puruse" to "pursue"
897	"	Change "bout" to "about"

PECO Transcript Corrections for the hearings held on December 17, 1985

Page	Line	Correction
923	12	Change "plan" to "plant"
924	2	Insert a comma after "rounds"

CERTIFICATE OF SERVICE

I hereby certify that on December 31, 1985 I served copies of the Transcript Corrections of Philadelphia Electric Company for Hearings on December 16-17, 1985, at Docket No. R-850152, upon the following by regular mail:

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
New Filing Section
Secretary's Bureau, Room B-18
North Office Building
Commonwealth and North Streets
Harrisburg, PA 17120

John Hanger, Esquire
Community Legal Services, Energy Project
3638 North Broad Street
Philadelphia, PA 19140

David M. Kleppinger, Esquire
100 Pine Street
Harrisburg, PA 17120

Zori G. Ferkin, Esquire
Governor's Energy Council
P.O. Box 8010
300 N. 2nd Street
Harrisburg, PA 17105

Scott Rubin, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

Mildred E. V. Pitts, Esquire
Information Resources & Utilities Division
General Services Administration
Room 4002
18th and F Streets, N.W.
Washington, DC 20405

Charles E. Rainey, Jr., Esquire
Municipal Services Building
Law Department, 15th Floor
Philadelphia, PA 19102

Scott C. Penwell, Esquire
Duane, Morris & Heckscher
203 Pine Street
P.O. Box 1003
Harrisburg, PA 17108-1003

Nancy Schuster, Esquire
1 Pond Street
Bristol, PA 19007

Patricia M. Gustin
Pennsylvania Public Utility Commission
Room G-33
North Office Building
Harrisburg, PA 17108

Earle H. O'Donnell, Esquire
Merrill L. Kramer, Esquire
Sutherland, Asbill & Brennan
1666 K Street, N.W.
Washington, D.C. 20006-2803

Mark P. Widoff, Esquire
Widoff, Reager, Selkowitz & Adler
129 State Street
Harrisburg, PA 17101

Michael Browne, Esquire
Reed, Smith, Shaw & McClay
1600 Avenue of the Arts Building
Broad and Chestnut Streets
Philadelphia, PA 19107

Honorable Joseph P. Matuschak
Pittsburgh State Office Building
300 Liberty Avenue
Pittsburgh, PA 15222

Wayne L. Emery, Esquire
Kenneth R. Pepperney, Esquire
Rafael Caminero, Esquire
600 Grant Street, Rm. 1580
Pittsburgh, PA 15230

Alan R. Squires, Esquire
Greenstein, Gorelick, Price,
Silverman & Laveson
900 Two Penn Center Plaza
Philadelphia, PA 19102

Anthony G. Tummarello
Director of Energy
Occidental Chemical Corporation
P.O. Box 4020
River Park
Darien, CT 06820

Frederick H. Knight

WASHINGTON
NEW YORK
LOS ANGELES

MORGAN, LEWIS & BOCKIUS
COUNSELORS AT LAW
ONE LOGAN SQUARE
PHILADELPHIA, PENNSYLVANIA 19103
TELEPHONE: (215) 963-5000
CABLE ADDRESS: MORLEBOCK
TELEX: 83-1315

MIAMI
HARRISBURG
LONDON

DAVID B. MACGREGOR
DIAL DIRECT (215) 963-5448

December 31, 1985

RECEIVED
DEC 31 1985
SECRETARY'S OFFICE
Public Utility Commission

Honorable Joseph P. Matuschak
Administrative Law Judge
Pennsylvania Public Utility Commission
97 East Main Street
Uniontown, PA 15401

Re: Pennsylvania Public Utility Commission v. Philadelphia Electric Company, Docket No. R-850152

Dear Judge Matuschak:

Enclosed is an original and 2 copies of Philadelphia Electric Company's Petition for Stay of the December 20, 1985 Order granting the Pennsylvania Public Utility Commission Trial Staff's Motion in Limine and excluding from the record certain evidence dealing with the reasonableness of the 1976 and 1978 Limerick construction deferral decisions.

As indicated in the attached Certificate of Service, copies of the enclosed Petition have been served upon all parties of record.

DOCUMENT FOLDER

Sincerely,

David B. MacGregor
Counsel for Philadelphia Electric Company

DBM/b
Enclosure
cc: All parties of record

DOCUMENT FOR DEP

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION :
:
v. : Docket No. R-850[illegible]
:
PHILADELPHIA ELECTRIC COMPANY :

DOCKETED
JAN 7 - 1986

PETITION FOR STAY

NOW COMES Philadelphia Electric Company ("PECO" or the "Company"), by its Counsel, and files this Petition with the Administrative Law Judge ("ALJ") for a stay of the December 20, 1985 Order granting the Pennsylvania Public Utility Commission Trial Staff's ("Trial Staff") Motion in Limine and excluding from the record certain evidence dealing with the reasonableness of the 1976 and 1978 Limerick construction deferral decisions. In support of this Petition, the Company represents as follows:

1. On November 20, 1985, the Trial Staff filed a Motion in Limine which would limit the evidence admitted and issues addressed in this proceeding to preclude consideration of the prudency of the 1976 and 1978 Limerick construction deferral decisions. As the sole basis for its Motion, the Trial Staff asserted that these decisions were found to be unreasonable by the Commission in Re Limerick Nuclear Generating Station, 56 Pa. P.U.C. 47 (1982), aff'd, 501 Pa. 153, 460 A.2d 734 (1983) (hereafter referred to as "1980 Limerick Investigation") and that, under Section 316 of the Public Utility Code (66 Pa.C.S. §316), such a finding is conclusive in the instant proceeding and precludes further litigation of this matter.

2. The Company filed an Answer to the Motion in Limine on December 5, 1985 and the Trial Staff filed a Reply to the Company's Answer on December 16, 1985. Oral argument on the merits of Trial Staff's Motion was held on December 20, 1985. On the basis of these submittals and oral argument, the ALJ granted the Trial Staff's Motion and ruled that (a) the 1980 Limerick Investigation record as it relates to the initial decisions to construct Limerick and the 1974, 1976 and 1978 construction deferral decisions is incorporated into the record in this proceeding; (b) the Commission's finding in the 1980 Investigation that the 1976 and 1978 deferral decisions were unreasonable is conclusive upon the parties to this proceeding; and (c) all evidence previously admitted in this proceeding which relates to the reasonableness of the initial decisions to construct Limerick and the decisions to delay construction are stricken from the record and any further evidence relating to these matters will not be admissible (Tr. 1374-1375).

3. Pursuant to 52 Pa. Code §5.302, the Company, on December 26, 1985, filed with the Commission a Petition for review of the ALJ's ruling and answer to the following material question:

> "Whether, contrary to the determination of the Pennsylvania Supreme Court in Pa. P.U.C. v. Philadelphia Electric Company, 501 Pa. 153, 460 A.2d 734 (1983), the criticism of the Company's 1976 and 1978 deferral announcements in the 1980 Limerick Investigation constituted a final adjudication which precludes the submission of any evidence on the prudence of such action in the current

proceeding, other than quantification of the consequences thereof."

It is the Company's position that this question should be answered in the negative in view of the Pennsylvania Supreme Court's clear holding that a final and binding adjudication was not rendered by the Commission. Moreover, to accord conclusive effect to the Commission's discussion of this matter would cause undue prejudice to PECO, violate the Company's right to due process and substantially disrupt the orderly conduct of this rate proceeding.

4. Where interlocutory review and answer to a material question is sought in a proceeding, Section 331(e) of the Public Utility Code specifically authorizes the ALJ to grant a stay, where necessary, to protect the substantial rights of the parties involved, as follows (66 Pa.C.S. §331(e)):

> "Interlocutory appeals - A presiding officer may certify to the commission, or allow an interlocutory appeal to the commission on any material question arising during the course of a proceeding, where he finds that it is necessary to do so to prevent substantial prejudice to any party or to expedite the conduct of the proceeding. The presiding officer or the commission may thereafter stay the proceeding if necessary to protect the substantial rights of any of the parties therein." (emphasis added)

5. A stay of the ALJ's ruling pending final resolution by the Commission should be granted in order to protect the substantial rights of both the Company and other parties to this proceeding. If a stay is not granted, opposing parties will not develop and file testimony on this matter in accordance with the schedule previously established for litigation of this

proceeding, and in the event that the Commission answers the material question presented to it by the Company in the negative and reverses the ALJ's determination, unnecessary delay and substantial prejudice to the rights of all parties will result.

Specifically, under the current schedule, the testimony of opposing parties on Limerick issues is scheduled to be filed by January 14, or in less than two weeks, and cross-examination of opposing party witnesses supporting that testimony will occur during the first two weeks of February. Rebuttal testimony by the Company on Limerick issues must be filed by February 19, Limerick-related surrebuttal must be filed on February 28, and Limerick-related sur-surrebuttal must be filed on March 7. All rebuttal, surrebuttal and sur-surrebuttal testimony will be subject to cross-examination on March 12-14 and the record in this proceeding will be closed on March 14. During the next 2 months, briefs must be prepared and filed and the ALJ must issue a recommended decision, after which exceptions and replies to exceptions will be submitted. The 7-month suspension period in this proceeding ends June 27, 1986, and a final Commission Order must be issued prior to that time.

As shown above, an extremely demanding schedule has been established which must be met to permit the efficient development of a complete and accurate record if a final Commission Order is to be issued within the time constraints of this proceeding. If a stay is not granted and the ALJ's ruling is ultimately reversed by the Commission, this schedule will be substantially and unnecessarily delayed to the prejudice of all parties. The

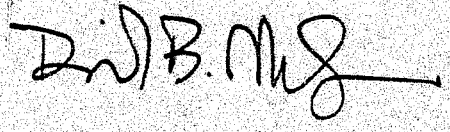
filing and development of rebuttal and surrebuttal testimony regarding the reasonableness of the construction deferral decisions as well as related cross-examination will be substantially delayed beyond the dates set forth above. As a result, all parties will be forced to accomplish these activities on an extremely compressed schedule in order to complete this proceeding within the statutory suspension period. Such delay and compression of the time needed for preparation of this testimony and cross-examination will substantially prejudice both the Company's and opposing parties' ability to fully and adequately develop the record on this important issue. Moreover, a delay in the submission of such significant evidence will disrupt the efficient and orderly conduct of this proceeding.

In contrast, if a stay is granted, then a full and complete record on the reasonableness of the deferral decisions can be developed in an orderly manner under the agreed upon schedule set forth above. Such a record is required if the Commission is to fully understand and resolve this issue in the event that the ALJ's ruling is reversed. However, even if the ALJ's ruling is ultimately upheld by the Commission, no party will have suffered because such a record has been developed. At most, additional evidence will have been prepared by all parties as was presumably contemplated in establishing the above schedule, which was established substantially before the Trial Staff's filing of the Motion in Limine and the ALJ's ruling. Clearly, the issuance of a stay will ensure that a complete and expeditious resolution to this matter is achieved, while denial

of a stay may result in substantial and avoidable prejudice and administrative burden.

WHEREFORE, for the reasons set forth above, the Company respectfully requests that its Petition for Stay be granted.

Respectfully submitted,



Walter R. Hall, II
David B. MacGregor
Jack E. Jerrett

Counsel for Philadelphia Electric Company

OF COUNSEL:

Edward G. Bauer, Jr., Esquire
Vice President and General Counsel
Philadelphia Electric Company
2301 Market Street
Philadelphia, PA 19101

Robert H. Young
William E. Zeiter
Jay H. Calvert, Jr.
MORGAN, LEWIS & BOCKIUS
2000 One Logan Square
Philadelphia, PA 19103

DATED: December 31, 1985

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the foregoing document upon all parties of record in this proceeding in accordance with the requirements of 52 Pa. Code §1.54.

Dated this 31st day of December, 1985.

DAVID B. MACGREGOR

Counsel for Philadelphia Electric Company

OF COUNSEL:

Edward G. Bauer, Jr., Esquire
Vice President and General Counsel
Philadelphia Electric Company
2301 Market Street
Philadelphia, PA 19101

MORGAN, LEWIS & BOCKIUS
2000 One Logan Square
Philadelphia, PA 19103
(215) 963-5700

Services Administration General Counsel Washington, DC 20405

January 2, 1986

RECEIVED
JAN 8 1986
SECRETARY'S OFFICE
Public Utility Commission

Mr. Jerry Rich, Secretary
Pennsylvania Public Utility Commission
Room G-18, North Office Building
North & Commonwealth Avenue
Harrisburg, Pennsylvania 17120

Dear Mr. Rich:

Re: Pennsylvania Public Utility Commission, et al.
v.
Philadelphia Electric Company
Docket No. R-850152

Enclosed for filing with the Commission are three (3) copies of the Testimony and Exhibits of Philip R. Winter, on Cost of Capital, General Services Administration, on behalf of the Federal Executive Agencies.

Sincerely,

Mildred E. V. Pitts

MILDRED E.V. PITTS
Senior Trial Attorney
Information Resources & Utilities Division

DOCUMENT FOLDER

Enclosures

cc: Honorable Joseph P. Matuschak
Administrative Law Judge
Pennsylvania Public Utility Commission

Mr. Joseph Brennan
Associated Utility Services
P. O. Box 650
Moorestown, NJ 08057

All Parties

CERTIFICATE OF SERVICE

Re: Pennsylvania Public Utilities Commission, et al.
v.
Philadelphia Electric Company
Docket No. R-850152

I hereby certify that I am, this 2nd day of January, 1986 serving either by special messenger or by first-class mail, the foregoing document, General Services Administration's Testimony and Exhibits of Philip R. Winter, upon the persons listed below:

Honorable Joseph P. Matuschak
Administrative Law Judge
Pennsylvania Public Utility Commission
97 E. Main Street
Uniontown, Pennsylvania 15401

Marlene R. Chestnut, Esquire
Assistant Counsel
Veronica A. Smith, Esquire
Daniel Delaney, Esquire
Office of Staff Counsel
Pennsylvania Public Utility Commission
North Office Building, Room G19
Harrisburg, Pennsylvania 17120

Walter R. Hall, II, Esquire
David B. MacGregor, Esquire
Robert H. Young, Esquire
Morgan, Lewis & Bockius
2000 One Logan Square
Philadelphia, Pennsylvania 19103

Irwin A. Popowsky
Scott J. Rubin, Esquire
David Wersan, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, Pennsylvania 17120

David M. Kleppinger, Esquire
Edward J. Riehl, Esquire
McNees, Wallace & Nurick
100 Pine Street
Harrisburg, Pennsylvania 17108

Janet Parrish, Esquire
Community Legal Service
Energy Project
3638 N. Broad Street
Philadelphia, Pennsylvania 19140

Zori G. Ferkin, Esquire
Governor's Energy Counsel
P.O. Box 8010
Harrisburg, Pennsylvania 17105

Jerry Rich, Secretary
Pennsylvania Public Utility Commission
Room B-18 North Office Building
North & Commonwealth Avenue
Harrisburg, Pennsylvania 17120

Michael L. Browne
Reed Smith Shaw & McClay
1600 Avenue of the Arts Building
Broad & Chestnut Streets
Philadelphia, Pennsylvania 19107

Franklin L. Kury
Reed Smith Shaw & McClay
300 North Second Street
P.O. Box 11844
Harrisburg, Pennsylvania 17108

Anthony G. Tummarello
Director of Energy
Occidental Chemical Corporation
P. O. Box 4020
River Park
Darien, CT 06820

Mildred E. V. Pitts

MILDRED E. V. PITTS

RECEIVED
JAN 3 1986
SECRETARY'S OFFICE
Public Utility Commission

GSA STATEMENT No. 1

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

DOCKETED
DOCKET
JAN 03 1986

DOCUMENT
FOLDER

Testimony of

PHILIP R. WINTER, CFA

Cost of Capital

on Behalf of the Federal Executive Agencies
General Services Administration

General Services Administration (PUR)
Room 6317
18th & F Streets, N.W.
Washington, DC 20405
(202) 566-1034

January 2, 1986

DIRECT TESTIMONY OF PHILIP R. WINTER

Q: PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS.

A: My name is Philip R. Winter. My business address is Office of Public Utilities, Rate Case Division, General Services Administration, 18th and F Streets, N.W., Washington, DC 20405.

Q: WHAT IS YOUR POSITION WITH THE GENERAL SERVICES ADMINISTRATION?

A: I am an Operations Research Analyst in the Office of Public Utilities, and am responsible for cost of capital and cost of service testimony in public utility rate cases. A statement of my educational background and professional experience is contained in Appendix A of this testimony.

Q: IN WHAT CAPACITY ARE YOU APPEARING BEFORE THIS COMMISSION?

A: I am appearing as a witness on behalf of the General Services Administration, representing the consumer interests of all the Federal Executive Agencies.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY HEREIN?

A: I address cost of capital issues, including Philadelphia Electric Company's (PECO or Company) cost of debt, cost of preferred and common equity, and appropriate capital structure.

Q: WHAT OVERALL COST OF CAPITAL IS APPLICABLE TO THE COMPANY IN THIS CASE?

A: The Company's overall cost of capital applicable in this case should reflect the effect of recent debt issuances and debt redemptions by the Company. Although data necessary for determination of the overall effect of these issuances and redemptions have been requested, such data are not, as yet, available. When data are available, I will file an update to Schedule 1 contained in this testimony, which will show the Company's cost of debt and overall cost of capital for the test year ending June 30, 1986.

Q: WHAT COST IS APPLICABLE TO THE LONG-TERM DEBT COMPONENT OF THE COMPANY'S CAPITAL STRUCTURE?

A: The company's filing shows a 10.74% estimated embedded cost of debt for the test year ending 6/30/86. This estimate is excessive, however, since (1) new debt has been sold at an

effective cost below the 12.5% estimate included in Company witness Brennan's testimony; (2) a portion of the Company's high coupon debt has been redeemed, thereby lowering the overall embedded debt costs; and (3) Mr. Brennan's estimate of yields on floating rate bonds is incorrectly based on Treasury bill futures contract yields.

Based on data from EBASCO, a business consulting firm, approximate costs to PECO for $250 million and $150 million of mortgage bonds sold on November 20, 1985 were 11.91% and 11.04%, respectively. The exact costs of these issues have not, as yet, been provided by Mr. Brennan, and the end result of the redemption of high coupon issues is unknown. The impact of the new issuances and redemptions on test year debt costs should be determined and then used in establishing PECO's overall cost of debt in this case.

With regard to the floating rate pollution control notes, my estimates of their effective costs are based on current consensus forecasts of T-bill yields as opposed to the T-bill futures contract yields on which Mr. Brennan relies (see his Schedule 4, p. 7). I utilize the consensus forecast of yields because they are known to represent current expectations for T-bill yields in 1986 while current T-bill futures contract yields do not. Supportive of my position on this issue is a statement by

Dr. Robert W. Kopprasch, vice president in the bond portfolio analysis group of Salomon Brothers. In a recent article entitled, "Options and Futures: Strategic Tools for Portfolio Management (Part I)," in Options and Futures: New Route to Risk/Return Management, 1984, pp. 8-17, Dr. Kopprasch states:

"... One of the major aspects of futures pricing is that you don't price the futures contract on expectations. The three-month contract is not priced based on where people think three-month rates will be ..."

Q: WHAT T-BILL FORECASTS ARE THE BASIS FOR YOUR ESTIMATE OF YIELDS ON PECO'S FLOATING RATE ISSUES?

A: I rely on the consensus forecasts for 1986 T-bill yields contained in the January 1, 1985 Blue Chip Financial Forecasts. These forecasts range from 7.0% to 7.3% for the four quarters of 1986. As a point estimate for use in this case, I have choosen 7.15%, and use this value in place of the 8.13% futures contract yield on which Mr. Brennan's calculations are based. For example, my estimated effective interest rate for the 1982 Series A pollution control note of 5.65% is calculated as follows:

(.6)(.0715)=.0429/.9846=.0436x$60,000,000=$2,614,260 + $777,462=$3,391,722/$60,000,000=5.65%

Effective yields on the remaining floating rate issues are calculated in a comparable manner. Results of these calculations, including the weighted cost rates, are shown in Schedule 2. An apparent error in Mr. Brennan's calculation of the weighted costs for the 5.50% Pollution Control Note of 1997 has also been corrected. The end result of these calculations is a reduction in the estimated costs of PECO's Pollution Control Notes from 9.51% to 9.31%.

Q: WHAT COST IS APPLICABLE TO THE PREFERRED STOCK OF THE COMPANY'S CAPITAL STRUCTURE?

A: Mr. Brennan's estimate for the cost of PECO's test year preferred stock is 10.54%. This estimate includes a preferred issue of $50 million scheduled for offering in May 1986 (TR 6, lines 14-16 and his Schedule 5, p. 2) at an estimated cost of 12.63%. In my opinion, this estimate is excessive just as Mr. Brennan's cost estimates for new debt have proven to be excessive. Recent preferred and preference stock issues by triple-B rated companies have fallen between 9.4% and 9.8% (based on issuances by Georgia Power and Commonwealth Edison on 12/5/85). Given these recent yields and Blue Chip forecasts for no change in 1986 interest rates from current levels, I consider a 10.0% cost estimate fully adequate. Replacing Mr. Brennan's 12.63% figure with my 10% estimate, lowers PECO's test year

cost of preferred stock from 10.54% to 10.41%. The 10.41% should be used in calculation of PECO's overall cost of capital.

Q: WHAT CONCLUSION HAVE YOU REACHED CONCERNING THE COST OF THE COMPANY'S COMMON EQUITY?

A: The current cost of the Company's common equity is between 15.1% and 16.1%. In today's capital market, I consider the midpoint of this range, 15.6%, a reasonable point estimate of the cost of equity. Documentation of my analysis of the Company's cost of equity is contained in the following pages. As is explained in the following, PECO's common equity is among the more risky publicly traded electric utility stocks because of its Limerick nuclear plant investments and associated problems. Without these problems PECO's stock would be considerable less risky and a significantly lower return would be required on the Company's capital.

If the Commission excludes part (or all) of the Limerick investment from rate base, because of an imprudency or excess capacity finding, my cost of equity recommendation shown above should be reduced to reflect this finding. Unless my cost of equity figures are reduced, the denial of Limerick rate base treatment would, on one hand, indicate

that current ratepayers are not responsible for Limerick costs while, on the otherhand, current ratepayers are responsible for the increment in my cost of equity finding that is, in fact, a cost of Limerick. To avoid this obvious inconsistency, a Commission finding of imprudency, or excess capacity, should be accompanied by a cost of equity finding that excludes any increment for the additional risks associated with the Limerick investment.

My estimate of the minimum increment due to Limerick in the above 15.1% to 16.1% cost of equity range is 50 to 100 basis points. This estimate is based on the belief that without Limerick PECO's dividend would be more secure, PECO's stock price would be less volatile, and dilution from new stock sales would be less likely. The overall effect of these and concomitant factors would reduce the risks associated with PECO's equity to a level more in line with bonds rated single-B by Moody's and Standard and Poor's Bonds in this risk category currently yield approximately 50 to 100 basis points less than my DCF findings as shown in Schedule 11.

Q: WHAT CRITERIA HAVE YOU UTILIZED TO DETERMINE THE CURRENT INVESTOR-REQUIRED RETURN FOR THE COMPANY?

A: I have applied the criteria established by the Supreme Court in the Bluefield and Hope decisions. In Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 693 (1923), the Court stated:

> "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."

In addition, as an indication of an upper bound on the return and the potential instability of investor return requirements, the Court stated (262 U.S. at 692-693):

> "...[the company] has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."

> "A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."

The Hope decision (FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944)) provided guidelines similar to those that I initially related from the Bluefield opinion, as follows:

> "...the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

Q: DO THE CRITERIA STATED IN THESE SUPREME COURT DECISIONS INDICATE UPPER AND LOWER BOUNDS FOR THE COST OF EQUITY?

A: In a general sense, they do. The lower bound is established as the return sufficient to maintain the Company's credit in the marketplace. Indications of the sufficiency of the return are the Company's success in raising necessary capital and the similarity of the after-tax return to the after-tax return on other investments of corresponding risks. Certainly, investors' capital will be attracted by those firms of corresponding risk that offer the higher after-tax returns. Unless the return offered by the regulated utility is competitive, the capital attraction criterion is unlikely to be met.

The upper bound on returns is stated to be below that realized or anticipated from highly profitable enterprises or speculative ventures. For high-grade utility firms, without consideration of the company's specific risk level, I believe yields-to-maturity on bonds rated below BBB by Standard & Poor's or Baa by Moody's may be used as an indicator of this upper bound. Such bonds are considered to be "predominantly speculative" or have "speculative elements", according to these rating services, and offer returns in excess of that generally required in the marketplace.

Q: GIVEN THE GENERAL SUPREME COURT GUIDELINES, HOW HAVE YOU DETERMINED SPECIFIC BOUNDARIES FOR THE COST OF THE COMPANY'S EQUITY?

A: I have first reviewed macroeconomic conditions that define the environment for today's credit market. Included in this review were expectations for, and recent trends in, the inflation rate, current Federal Reserve policy on monetary growth, and loan demand at large commercial banks. These interrelated factors are primary determinants of the cost of money. Secondly, I have performed a current market analysis of utility stocks, in general, and of PECO's common stock, specifically, to determine the Company's current cost of equity. Finally, I have reviewed cost of capital trends to

equity for the period during which rates from this case will be in effect.

Q: WHY DO YOU BEGIN YOUR ANALYSIS OF THE COMPANY'S COST OF EQUITY WITH A REVIEW OF CURRENT MACROECONOMIC CONDITIONS?

A: As indicated above, macroeconomic conditions including the supply and demand for funds in the U.S. economy and the rate of inflation are primary determinants of the general rates of interest (costs) on borrowed or invested capital. These general costs establish the base from which a specific company's cost of capital is determined.

Q: HOW ARE THE FEDERAL RESERVE'S MONETARY POLICY, THE INFLATION RATE, LOAN DEMAND, AND THE COST OF MONEY RELATED?

A: The interrelationships of these factors are multifaceted and complex. In basic terms, however, a tight monetary policy with stable loan demand tends to decrease the rate of inflation and place upward pressure on interest rates in the short-term. Over the long-term, interest rates would be expected to decline as inflationary pressures cool. Similarly, a policy toward increasing monetary growth with stable loan demand has tended to reduce interest rates over the short-term (due to the more plentiful supply of money),

but exert upward pressure on the inflation rate. Over the long-term, interest rates would be expected to rise with the increasing rate of inflation. Short-term effects of monetary growth on interest rates may be lessened or increased by fluctuating loan demand, level of foreign investment in U.S. securities, and changes in velocity, i.e., the average number of times per year that a dollar is used to purchase components of GNP.

For example, heavy demand for business loans during the first quarter of 1985 (loan growth at a 9% annual compound rate) placed upward pressure on interest rates even with relatively rapid growth in the money supply (9% growth in M1). Relatively flat or declining demand for business loans coupled with continued rapid growth in the money supply has more recently contributed to interest rate declines from the March, 1985, level.

Q: WHAT HAS BEEN THE RECENT MONETARY POLICY OF THE FEDERAL RESERVE?

A: Recently stated goals of the Federal Reserve are "to foster monetary and financial conditions that will help to reduce inflation further, promote growth in output on a sustainable basis, and contribute to an improved pattern of international transactions" (see Record of Policy Actions of the

Federal Open Market Committee, Meeting of October 1, 1985). To achieve these goals, the Federal Reserve has allowed monetary growth somewhat above its 1985 target growth range of 3% to 8% (for M1). Primary concerns of the Federal Reserve's policy committee include the large Federal deficit, the strength of the dollar and its affect on American exports, and the potential for renewed inflation. The first two concerns (the deficit and strength of the dollar) may be alleviated over the short-term by more rapid monetary growth, i.e., higher monetary growth would likely reduce interest rates thereby easing the pressures of Federal borrowing and reducing the attractiveness of the dollar. Higher monetary growth, however, may reignite inflation.

Even with the recent rapid growth in M-1, the Committee has not found signs of higher inflation rates. Instead, prices and wages have risen at rates similar to, or below, those recorded earlier in the year. Notwithstanding the favorable reports on inflation, some slowing of monetary growth is believed desirable and action has been taken to effect such a slowdown.

Q: WHAT HAS BEEN THE RECENT PATTERN IN INFLATION RATES?

A: Inflation rates have dropped significantly since the early 1980's and have continued to decline in 1985 (see Schedule 3, Part 1). Recent quarterly data (for July, August and September 1985) show inflation rates that are among the lowest recorded in the past twenty years. The third quarter rate on an annualized basis is 2.3%, which is approximately 55% of the first quarter value.

Numerous factors including declining oil prices, strength of the dollar against foreign currencies, and Federal Reserve policy have contributed to favorable inflation rate trends. The trends are expected to continue due to strong competition from foreign producers and likely further declines in oil prices associated with dissension within OPEC.

Q: WHAT IS THE CURRENT OUTLOOK FOR INFLATION?

A: Expectations for future inflation are commonly believed to be based on historical rates, with the more recently experienced rates of increase carrying the greatest weight. The pattern of inflation has stabilized since early 1984, and current low levels of inflation are generally expected in the coming months. According to the December 10, 1985

issue of Blue Chip Economic Indicators, price inflation during 1985 will be near 3.5%. Forecasts for 1986 indicate expectations for consumer prices to rise at a 3.7% annual rate. Recent inflation forecasts by major forecasting firms are shown in Schedule 3, Part II. Inflation rate expectations of these forecasters range between 3.1% and 4.4% for the period 1985-86.

Q: WHAT HAS BEEN THE IMPACT OF INFLATION, LOAN DEMAND, RECENT FEDERAL RESERVE POLICY, AND OTHER SIGNIFICANT FACTORS ON THE CREDIT MARKETS?

A: Recent interest rates on bonds and other fixed yield investments are shown in Schedule 4. Average yields on fixed income securities trended downward from the summer of 1984 through January 1985. Fixed income security yields dropped 150 to 350 basis points during this period. The Federal Reserve's restraint on monetary growth and increased loan demand in early 1985 subsequently led to a plateau in yield trends followed by increases of 50 to 100 basis points. Subsequent to mid-March, 1985, interest rates in general have dropped significantly. Declines of 100 to 150 basis points have led to the lowest yields experienced since the late 1970's. Contributing to the general declining trend in fixed income yields has been heavy foreign investment in U.S. securities, adequate money supply

relative to demand, moderate levels of unemployment, and noninflationary levels of U.S. capacity utilization.

Q: WITHIN THE SCENARIO DESCRIBED ABOVE OF M1 GROWTH NEAR THE UPPER END OF THE FEDERAL RESERVE TARGET RANGE OF 3% TO 8% AND A PLATEAU IN INFLATION RATE TRENDS, WHAT IS THE OUTLOOK FOR THE COST OF CAPITAL?

A: If inflation continues to fall near 3% and credit demands are consistent with allowed monetary growth without oil, or other price shocks, interest rates should decline. Alternatively, more restrictive monetary, growth coupled with strong demands for credit, will exert upward pressure on current rates. As reflected in the January 1, 1985 issue of Blue Chip Financial Forecasts, the consensus opinion is for no change in capital costs during 1986 and early 1987 with seasoned A-rated utility bond rates of 11.0%.

Q: WITH THE CURRENT ECONOMIC ENVIRONMENT CHARACTERIZED BY INFLATION EXPECTATIONS OF 3.5% to 4.5% AND A MODERATE FEDERAL RESERVE MONETARY POLICY, WHAT HAS BEEN THE PERFORMANCE OF ELECTRIC UTILITY STOCKS IN GENERAL?

A: Utility stock price trends, as indicated by the Dow Jones and Standard and Poor's utility indices, are shown

graphically in Schedule 5 for the period August 30, 1985 to December 13, 1985. Both indices reflect downward price movements of approximately 6% during the first five weeks of this period. During the remaining eleven weeks, these price declines were erased as price increases totaling 12% - 16% were recorded. The recent price improvement has been attributed to interest rate declines, continuing low levels of inflation, and improvement in quality of earnings.

Q: HAS THE COMPANY'S PERFORMANCE BEEN SIMILAR TO THAT OF OTHER ELECTRICS?

A: Schedule 6 shows PECO's stock price trend to be similar to that of the indices. Price declines for the stock during the initial six weeks of the period, totaled almost 5.8%, somewhat less than that of the utility indices, while subsequent increases were approximately 19%. In addition to the favorable interest rate trends and other contributing factors described above, recent appreciation in PECO's stock is attributable to indication from the Pennsylvania Public Utility Commission that Limerick #2 construction could continue if certain requirements were satisfied.

Q: OF WHAT IMPORTANCE IS PECO'S RECENT STOCK PRICE TREND TO YOUR DETERMINATION OF THE COMPANY'S RETURN REQUIREMENTS?

A: Stock prices carry information concerning investor return expectations and requirements. Prices recorded for PECO'S stock represent the consensus opinion of the marketplace on the stock's value, given the current and prospective growth expectations and discount rates.

Theoretically, a stock's value is equal to the present value of expected future returns from investing in the stock. The future returns are in the form of dividends and price appreciation. From a knowledge of investors' expectations for dividend growth and price appreciation, investor return requirements may be estimated. By adjusting investor return requirements for the effects of flotation cost and market pressure (if any), PECO's return requirements on equity may be estimated.

Q: IN GENERAL, WHAT IS THE RELATIONSHIP BETWEEN A COMPANY'S STOCK PRICE TREND AND INVESTOR RETURN REQUIREMENTS?

A: In general, increasing stock price trends in the short-term are a result of an increase in expected returns from the stock or a decline in investor return requirements. Similarly, decreasing stock price trends imply decreasing expected returns or rising required returns. For example, recent price appreciation in PECO's stock is a sign of declining costs of equity to PECO.

Q: PECO'S STOCK PRICE PERFORMANCE SHOULD BE SUPPORTED BY THE COMPANY'S UNDERLYING FUNDAMENTALS. WHAT IS THE RECENT TREND IN THESE FUNDAMENTALS, AND HOW DO THEY COMPARE WITH MOODY'S ELECTRICS AND WITH LARGE CORPORATIONS IN GENERAL?

A: A review of fundamental ratios indicative of PECO's recent performance (see Schedule 7), reveals the following: PECO's after-tax profit margins increased steadily and significantly between 1981 and 1984. During this three year period, profit margins increased 45%, reflecting an annual compound growth rate of 13.1%. The Company's profit margins are consistently above those recorded by Moody's Electrics, and differences in margins became wider, as opposed to narrowing, during this period. At the end of 1984, PECO's

margins were more than 1.3 times those recorded by the Moody's index of electric utilities. PECO's margins compare even more favorably with those recorded for large corporations. The large corporations recorded a drop in margins during 1982, and as of 1984 had not exceeded 1981 levels. PECO's margins were 2.3 times the large corporate margin at the beginning of this period (1981) and more than 3.3 times the corporate average in 1984.

On the other hand, PECO's returns on equity (ROE) for the years 1981 through 1984 consistently fell below those recorded by Moody's Electrics. Some relative improvement in PECO's ROE was, however, recorded during this period with a 1984 shortfall from the Moody's average of 2.8%, compared with a shortfall in 1981 of 4.2%. Relative to the large corporation averages, PECO's ROE improved consistently during the period. While PECO's ROE was below the corporate average in 1981, its ROE exceeded the corporate figure by almost 7% in 1984.

Q: WHAT FACTORS EXPLAIN THE DIFFERENCE BETWEEN PECO'S RECENT ROE AND THE COMPARABLE ROE FOR MOODY'S ELECTRICS?

A: Part II of Schedule 7 offers insight on the factors contributing to the shortfall of PECO's ROE from the Moody's average. This exhibit shows that PECO's ROE was 2.8% below

the Moody's average in 1984. This shortfall was due to a lower turnover rate (Revenues/Total Capital), and lower pre-tax profit margin (Pre-tax Profits/Revenues) than that recorded for Moody's Electrics. PECO's turnover ratio is 21.7% below the Moody's figure. This low turnover ratio shows that PECO has been unable to generate revenues from invested capital at the same level attained by the average utility. An apparent cause of the relatively low turnover ratio is PECO's investment in the Limerick plants and the lack of revenues from these plants.

PECO's pre-tax profit margin, which is 8.49% below the Moody's average, indicates management's ability to capture profits from revenues. The below average profit margin for 1984 may be attibutable to the need for greater utilization of generating capacity and improved control of operating costs.

Q: WHAT METHODS HAVE YOU USED TO DETERMINE THE COST OF EQUITY TO PECO?

A: To estimate return requirements, I rely most heavily on the discounted cash flow (DCF) approach, an approach that uses a company's stock price along with expectations for dividend growth and price appreciation, to estimate investor

return requirements. I also use an historical risk premium approach, and review current return requirements on alternative investments of varying risks to check the reasonableness of results from the DCF method.

Q: WHAT ASSUMPTIONS OR JUDGMENTS MUST THE ANALYST MAKE WHEN APPLYING THE DCF METHOD?

A: Primary assumptions in application of the DCF method are that the price paid for a security is an "equilibrium" price and is equal to the discounted stream of investor-"expected" dividends and price appreciation over the investor-holding period. The discount rate that equates a company's stock price to these expected returns is an indication of the investor-"required" rate of return. Algebraically, these assumptions may be expressed as shown in Schedule 8.

Q: WHAT JUDGMENTS MUST THE ANALYST MAKE BEFORE APPLYING THE DCF MODEL?

A: To apply the DCF model, the rate of return analyst must make decisions about the following items:

1. What is the investor-expected growth in dividends during the investment horizon, and does the expected growth rate change over time?

2. What stock price is representative of current investor return requirements, e.g., the price of the stock on a specific date; the average price over the most recent 12 weeks, 16 weeks, or other period?

3. What is the investor's expected holding period or investment horizon, i.e., the future period over which the investor makes assumptions about potential returns?

4. What is the expected change in the stock's price during the investment horizon?

Q: WHAT FORM OR VERSION OF THE DCF MODEL HAVE YOU USED IN THIS CASE?

A: I rely on a "two-stage" model that allows explicit consideration of varying price and dividend growth rates over time.

Q: DOESN'T THE COMMONLY USED "YIELD PLUS GROWTH," i.e. D/P + g FORM OF THE DCF MODEL ALLOW CONSIDERATION OF GROWTH RATES THAT VARY OVER TIME?

A: No, it does not. The "yield plus growth" form of the DCF model is obtained from the longer version shown in Schedule 8 only if the assumption is made that price and dividends grow each year at a constant rate. In fact, if the D/P + g version is properly used, the analyst will concentrate on determination of an expected long-term growth rate as opposed to relying solely on near-term estimates. Strictly speaking, the growth rate used in this simple form of the model is assumed to continue through infinity without change.

Q: IN ESTIMATING RETURN REQUIREMENTS FOR PECO, WHAT OTHER ASSUMPTIONS ARE IMPLICIT IN THE CONSTANT GROWTH MODEL?

A: The constant growth DCF model also implicitly assumes that the market price, earnings and book value of the company's common stock each grow at the same constant rate as dividends. Since a review of individual utility companies' short- or long-term performance (see Schedule 10) will show that these constant growth conditions are seldom experienced, constant growth assumptions are unlikely to be representative of investor expectations. If inaccuracies

associated with the unrealistic constant growth assumption are to be minimized, the growth rate used must reflect the composite long-term growth expectations for all these elements i.e., price, dividends, earnings, and book value. Failure to consider composite growth rate expectations, especially for determination of long-term growth prospects, may lead to significant errors in DCF findings.

Q: WHY IS THE TWO-STAGE MODEL THAT CONSIDERS DIFFERING RATES OF GROWTH MORE APPROPRIATE THAN THE SINGLE-STAGE, OR CONSTANT GROWTH MODEL?

A: The two-stage model is most applicable to this case because little growth in PECO's dividend, or possibly a cut, is expected in the near term. Although the dividend appears secure at present, PECO's Board of Directors has frequently mentioned the likelihood of a dividend reduction if a Limerick plant is cancelled. Once the financial strain associated with Limerick construction has been alleviated, however, growth in PECO's dividends should return to more typical levels. Since the two-stage model allows explicit modeling of an initial low growth period, followed by a return to normal growth levels, it allows a closer match of reality than the single-stage model with its constant growth assumptions.

Q: IS THE TWO-STAGE, OR MULTISTAGE, DCF MODEL ACCEPTED IN THE INVESTMENT AND ACADEMIC COMMUNITIES?

A: Yes, it is. Kidder, Peabody; Prudential-Bache; Salomon Brothers; Drexel, Burnham and Lambert; Goldman, Sachs & Co.; and others currently use multistage DCF models to estimate investor return expectations on common stock. Also academicians, such as David Hawkins of Harvard University, Eugene Brigham of the University of Florida, and Fred Weston of the University of California (Los Angeles), recognize the need for multistage models in texts they have authored.

Q: WHAT ARE THE BOUNDARIES OF THE TWO GROWTH PERIODS YOU EMPLOY IN THE DCF MODEL AND WHAT IS THE LOGIC FOR YOUR SELECTION OF THESE BOUNDARIES?

A: I recommend a DCF model of the following form:

$$P = \sum_{i=1}^{5} D(1+g_1)^i/(1+k)^i + \sum_{i=6}^{\infty} D(1+g_1)^5(1+g_2)^{i-5}/(1+k)^i$$

where "P" and "D" are the current price and dividend, respectively, "g_1" is the average annual growth rate expected within the next five years, "g_2" the average annual growth expected over the long term, and "k" is the investor-required return.

The near-term boundary defines a five-year forecast period. Forecasts covering a period of this length are frequently published by investment services and are generally available to investors. Value Line, Dean Witter, Merrill Lynch, and Salomon Brothers are among the better known firms providing forecasts for this period.

Because of the broad circulation of such forecasts and the relative accuracy with which five-year forecasts may be made, I believe this period receives particular attention by investors. Forecasts and expectations beyond the four to five year period become less certain and may vary widely. Using the above rationale, I have selected a five-year period for the initial stage of the DCF model.

Q: ON WHAT DATA HAVE YOU RELIED TO ESTIMATE GROWTH RATES APPROPRIATE FOR USE IN THIS MODEL?

A: I rely on investment firm growth forecasts for PECO for both the near- and long-term growth rates. In addition, I have reviewed long-term growth histories for both regulated and unregulated firms.

Q: WHAT ARE INVESTMENT FIRM FORECASTS FOR PECO GROWTH DURING THE FIRST STAGE OF THIS MODEL?

A: Relying on the most recent reports available from various investment firms, I have found the following. Value Lines's forecasts, dated September 27, 1985, indicate expectations for annual dividend, earnings, and book value growth from the end of 1985 to the end of 1989 to average 2.2%, 1.4%, and 2.2%, respectively. Prudential-Bache, in its October 1985 Quantum report, expects no growth in dividends or earnings during the next five years. Merrill Lynch, in its November/December 1985 Quantitative Analysis report, projects five-year growth rates for dividends and earnings of 1.8% and -2.3%, respectively. Salomon Brothers' November 15, 1985, Monthly Stock Review indicates expectations for five-year dividend and earnings growth rates of 1.0% and 2.0%, respectively. Duff and Phelps' May 17, 1985 Common Stock Summary reports expectations for no change in dividends over the near term. E.F. Hutton, in its September 1985 Equity Research report, foresees no near-term growth in dividends nor earnings.

Finally, Dean Witter's October 21, 1985 Equity Research publication contains five-year dividend and earnings growth forecasts for PECO of 2.0% and 2.5%, respectively. Near-term dividend growth rates estimated by these investment firms range between 0.0% and 2.2%, and are summarized in Schedule 12.

Q: WHAT ARE YOUR FINDINGS FROM REVIEW OF SHORT-TERM HISTORICAL GROWTH RATES FOR PECO?

A: Historical, five-year holding period, price, and dividend growth rates are shown in Schedule 9. For the ten most recent five-year holding periods with December 1 boundaries, e.g., Dec. 1, 1979 to Dec. 1, 1984; Dec. 1, 1978 to Dec 1, 1983, dividend growth rates have averaged 2.6%. Price growth rates during these same ten, five-year holding periods have not kept pace with dividend growth, and price declines have frequently been recorded. The average price growth for the ten most recent five-year growth periods is -1.1%.

Q: WHAT IS YOUR CONCLUSION CONCERNING PECO'S NEAR-TERM GROWTH RATE?

A: Based on review of forecasts from investment services and the historical short-term growth history, most investor short-term growth expectations fall between 0.0% and 2.0%. The possibility of a dividend reduction due to the Limerick investment and a preponderance of forecasted growth rates near 0.0%, make the lower end of the above range the more appropriate for use in the DCF model. Also, PECO's history of negative short-term price growth, the absence of further interest rate declines (that contributed to price growth in the recent past), and the Commission's decision in Docket No. R-842651 that denied a return on the common equity portion of PP&L's Sesquehanna plant #2, are all factors that tend to support the lower end of this growth rate range. In light of the above, I consider growth rates between 0.0% and 1.0% representative of most investors' expectations for PECO. I employ this range in the two-stage DCF model, along with long-term growth expectations, to estimate current investor return requirements.

Q: WHAT FACTORS AFFECT INVESTORS' EXPECTATIONS FOR GROWTH DURING THE SECOND STAGE OF THIS MODEL?

A: Considerable uncertainty surrounds the timing of PECO's return to growth rates more typical of the electric industry. Most of this uncertainty is due to construction of Limerick Unit #2. If this unit is completed, associated needs for new financing will have a weakening influence on the Company's balance sheet and potential rate base treatment of the unit will be a source of concern to investors. If Unit #2 is cancelled, a dividend cut is likely as has frequently been brought to the attention of PECO shareholders during meetings with PECO management. While the investment community currently appears to believe Unit #2 will be completed, this outcome is far from certain, and a dividend cut remains a possiblity.

Uncertainty related to the Limerick project will likely continue until the early 1990s, given the current construction schedule. Delays and other difficulties that have plagued most nuclear projects may prolong these uncertainties into the mid-1990s. Even after construction is completed, associated requirements such as the need for a water supply for cooling (that may affect the Unit #1 in-service date) could delay the return of PECO to a more typical period of growth.

Q: IN LIGHT OF THESE FACTORS UPON WHICH PECO'S RETURN TO TYPICAL GROWTH IS DEPENDENT, WHAT GROWTH RATE RANGE HAVE YOU FOUND REASONABLE FOR THE SECOND STAGE OF YOUR DCF MODEL?

A: I consider a growth rate range of 1.0% to 2.0% representative of investor expectations for long-term PECO growth. Although this range falls below the current steady-state (long-term) earnings growth forecast of 2.9% by Merrill Lynch, it is above the rate of growth experienced by PECO investors during any recent long-term period. For example, PECO's dividend growth during the last 20 to 25 years has averaged between 2% and 3%, but such growth has been more than offset by declines in PECO's stock price. Price declines have averaged near -3.5% during this period. Since PECO's stock has not demonstrated an ability to provide positive growth to investors, it appears investors are demanding their return up front, in the form of dividend yield, and are expecting little return in the form of growth. Supportive of this position is PECO's recent dividend yield of 14.5%, which is among the highest (if not the highest) of yields available on electric utility stocks today. PECO's yield is almost 600 basis points above the 8.8% current average yield for the industry.

Also, in the case of a dividend cut, the eventual return to a 3% or 4% long-term growth rate (which is the typical actual long-term growth rate for the industry) would not represent a 3%-4% average growth rate from current dividend levels. For example, if PECO's dividend is halved (comparable to Kansas Gas and Electrics' dividend cut after Commission disallowance of a portion of the Wolf Creek nuclear plant), then followed by 3% annual growth over the next 30 years, the annual growth rate from PECO's current dividend is only 0.6%. The 0.6% figure is obtained by noting that PECO's current dividend of $2.20, if halved, would be $1.10, and would increase to $2.67 ($1.10*(1.03^30=$2.67) after 30 years of 3% annual growth. But the $2.67 dividend represents only a 0.647% annual growth rate over the $2.20 current dividend since (1.00647^30)*$2.20=$2.67. Therefore, in the event of a dividend cut, even the 1.0% to 2.0% long-term growth rate range that I have found reasonable may be excessive.

Q: WHAT IS THE CURRENT DIVIDEND YIELD TERM OF YOUR DCF EQUATION AND HOW WAS IT DERIVED?

A: The current dividend yield (D_o/P_o) is 14.5%. This yield is computed as the average of the quotients of end-of-week stock prices and effective annual dividend rates from the most recent 16-week period (8/30/85-12/13/85). A period of

this duration is necessary to level the effects of temporary price fluctuations. Also the 16-week period, as opposed to a shorter period, is less likely to be fully contained within a peak or valley in the price pattern.

If significant trends in price movement are observed during the period, information conveyed by these trends should be incorporated in the final decision concerning the cost of equity. PECO's stock price varied from $14.125 to $16.75 during this period, based on end-of-week prices, and the indicated annual dividend was $2.20 per share. The most recently recorded prices are at the upper end of this range.

Q: WHAT ARE YOUR CONCLUSIONS FROM THE TWO-STAGE DCF MODEL CONCERNING INVESTOR RETURN REQUIREMENTS ON PECO's STOCK?

A: A current dividend yield of 14.5%, coupled with near- and long-term expected growth rates of 0.0% to 1.0% and 1.0% to 2.0%, respectively, indicate investor requirements of between 15.09% and 16.09%. In terms of the "yield plus growth" or "constant growth" model, my analysis indicates investors expect constant annual dividend and price growth rates between 0.5% and 1.4%, i.e., 15.09 = (1.005) 14.5 + 0.5 and 16.09 = (1.014) 14.5 + 1.4.

Q: WHAT ARE THE POINTS OF DISAGREEMENT BETWEEN YOUR DCF RESULTS FOR PECO'S AND THOSE OF COMPANY WITNESS BRENNAN?

A: Mr. Brennan's DCF finding of a 16.7% cost of equity (before a flotation cost adjustment), (Brennan Testimony, p. 40 lines 1-3), is based on a company specific dividend yield of 15.0% and a growth rate of 1.7%. The most significant shortcomings in these findings are described below.

Mr. Brennan's yield figure is based on the spot yield for September 9, 1985 and on the recent 12-month average yield for PECO (see his Schedule 14, p. 2). He "inflates" both the spot and 12-month average yield by 2.4% to reflect his findings for next-period dividend growth. As a final step, he averages four yields, the "inflated" and "uninflated" spot yields and the "inflated" and "uninflated" 12-month average yields. While it is unclear why his composite of "spot" and 12-month average yields is, or should be, representative of current investor return requirements, at least two shortcomings in his findings are apparent in this approach. The first is that spot yields are too volatile for use in determining overall market return requirements on PECO's stock. For example, PECO's recent yield has ranged between 13.1% and 14.5%, some 50 to 190 basis points below Mr. Brennan's figures. A second shortcoming is that Mr. Brennan's next period dividend is based on a 2.4% growth

rate which is inconsistent with the 1.7% growth figure he has found reasonable for PECO. It is interesting to note that the 2.4% is based on 3.5% short-term historical growth rate (see column 7 of his Schedule 15, p. 1) a growth rate that is well above even the most optimistic investment firm growth rate forecast. If Mr. Brennan were to rely on current market data and investment firms' growth forecasts, his yield finding would be reduced by approximately 50 basis points.

Mr. Brennan's constant, long-term growth rate of 1.7%, is based completely on analysts' short-term earnings and dividend growth forecasts and on PECO's short-term dividend growth history (see his Schedule 15, p. 1). He ignores the long-term growth forecasts from Merrill Lynch and ignores the long-term composite price and dividend growth rate history for PECO. By ignoring prospects for PECO's price growth, he violates a theoretical basis for the DCF technique that he specifies on page 23, lines 1-7 of his testimony; that is, the investor-expected return includes both dividend yield and stock price appreciation. If Mr. Brennan were to exclude the 3.5% short-term historical dividend growth rate from calculation of the 1.7% average and include, instead, growth rates that are probable over the long-term for both price and dividends, his growth rate findings would be reduced by 50 to 100 basis points.

Q: WHAT OTHER ANALYSIS HAVE YOU PERFORMED TO REACH CONCLUSIONS ABOUT INVESTOR RETURN REQUIREMENTS ON COMMON EQUITY?

A: As a check on the reasonableness of my DCF findings, I have calculated historical risk premiums between a portfolio of utility stocks and long-term Government bonds. I have also considered recent indications from the investment community on the current risk premium between stocks and bonds.

Q: ARE HISTORICAL RISK PREMIUMS USED BY THE INVESTMENT COMMUNITY TO MAKE INVESTMENT DECISIONS?

A: Historical risk premiums are widely used by members of the investment community, and background on this methodology is frequently included in required reading material for the training of financial analysts. The Ibbotson and Sinquefield findings have particularly widespread application, and are frequently used by portfolio managers in the development of scenarios of prospective returns available from stock investments.

Q: WHAT IS THE RATIONALE FOR USE OF HISTORICAL RISK PREMIUMS?

A: The rationale underlying use of historical risk premiums is that investors are risk averse, and that incentives in the form of higher expected returns are required to convince investors to purchase more risky securities. Historical data suggest that investors have generally been rewarded for assuming such risks. As shown in Schedule 13, a portfolio of the S&P Index stocks offered the greatest total return since 1928, followed by a portfolio of utility stocks, then government bonds. These long-term returns are consistent with general perceptions of the relative risks of these three groups of securities compared with the higher returns associated with the more risky securities.

By comparison of historical returns from investments of differing risks, risk premiums previously available to investors may be calculated. The statistical distribution of these premiums depicts past investor experience, and is indicative of premiums likely to be available in the future. Premiums falling in the tails of the distribution are improbable and, in most cases, would not be representative of investor expectations. I believe, however, that average historical premiums, for varying holding periods, and over an extended time frame, are a reasonable proxy for investor-expected premiums over the long term.

Q: ARE HISTORICAL LONG-TERM RISK PREMIUMS AN ACCURATE INDICATION OF CURRENT INVESTOR REQUIREMENTS?

A: Long-term historical premiums may, or may not, be representative of current investor requirements. An increase in the riskiness of bonds relative to stocks (such as that occurring since late 1979), may reduce the risk premium between these two types of securities. Similarly, changes in the relative tax treatment of returns on bonds and stocks may change the historical risk/return relationship.

Q: WHAT HISTORICAL RISK PREMIUMS HAVE YOU FOUND BETWEEN UTILITY STOCKS AND BONDS?

A: I have found that, based on geometric mean returns, a portfolio of Moody's 24 Utilities, during the period 1929 to 1984, returned approximately 182 basis points more than long-term Government bonds. To be consistent with my belief that the risk premium be based on available returns over varying holding periods and an extended time frame, I have computed the average of the premiums that would have been

realized over all whole-year holding periods of one year to ten years during 1929-1984. Only those holdings periods with end-of-calendar-year boundaries were considered. The average premium from this analysis was 359 basis points for utility stocks over Government bonds.

Q: WHAT DATA HAVE YOU USED TO CALCULATE THESE RISK PREMIUMS?

A: For Government bonds, I have used the bond data described by Ibbotson and Sinquefield in their publications of various titles, such as Stocks, Bonds, Bills, and Inflation: The Past (1926 - 1976) and the Future (1977 - 2000) and updates to these publications including Stocks, Bonds, Bills, and Inflation - 1985 Yearbook. For the utility stock data, I have relied on the monthly price and dividend data found in Moody's Public Utility Manual. These utilities include representative privately owned, electric and gas utility companies, that are dispersed geographically across the nation.

All dividends are assumed to be reinvested at the closing price for the month in which they were received. The long-term historical period chosen for analysis was 1929 to 1984. Data prior to 1929 are not available from the Moody's Manual on the Moody's stock index.

Q: HAVE SIGNIFICANT CHANGES IN THE RISK PREMIUM BETWEEN UTILITY STOCKS AND BONDS OCCURRED RECENTLY?

A: Yes, significant changes have occurred. For example, the October 1979 policy change of the Federal Reserve had a significant impact on interest rate volatility and, in turn, on required risk premiums. Although both stocks and bonds are interest rate sensitive, the greatest impact of this change has been felt in the bond market. Articles in the Wall Street Journal and Federal Reserve statistical papers have highlighted this impact. For example, an October 29, 1980, article in the Journal noted that "Bond buying these days has become a greater gamble than buying stocks. That once unthinkable notion is now widely accepted by investors ..." Also, the investment firm of Goldman Sachs reported in an April 1981 research paper that the average equity risk premium over bonds was - .5% at that time.

More recent publications from Merrill Lynch, ("Valuation Perspectives", dated April, 1985) and Salomon Brothers ("Valuation Focus-November 1985," dated November 11, 1985) indicate that the reduced risk premiums between stocks and bonds recorded in 1979-1981 continue to prevail. These reports also clearly point out that bond price volatility continues to exceed that of stocks in general. A logical conclusion from this increased bond volatility is stated in

the Salomon Brothers' pubication:

" ...[this volatility] confirms what many have argued: Bond markets have become so jumpy that their risk reaches or exceeds that of stocks ..."

Q: BASED ON THE RESULTS FROM YOUR RISK PREMIUM STUDY, WHAT CONCLUSIONS HAVE YOU DRAWN CONCERNING THE REASONABLENESS OF YOUR DCF-DETERMINED INVESTOR RETURN REQUIREMENTS ON PECO'S COMMON STOCK?

A: I believe that the 182 to 359 basis point premiums calculated for Moody's 24 Utilities over long-term Government bonds should be the starting point for determining the risk premiums for PECO'S stock. These premiums represent an average of long-term historical premiums for medium grade utilities.

The increased volatility in the bond market favors the lower end of the historical risk premium range. Since the average yield on long-term Treasury securities during a recent 16-week period (8/30/85 - 12/13/85) has been 10.5%, my DCF findings of 15.1% to 16.1% offer risk premiums of 460 to 560 basis points. These premiums fall above the average premiums that have been available to investors in utility stocks over the long-term as would be expected due to

greater than average risks currently associated with PECO's stock.

My DCF findings also indicate a risk premium between PECO common equity and PECO medium to long-term first mortgage bonds of 220 to 590 basis points. This finding is based on recently recorded yields-to-maturity on PECO bonds that mature in 10 to 20 years. Since early September 1985, these bonds have yielded 10.3% to 12.9%, with the longer term bonds requiring the higher yields. Since PECO's common equity is, in a sense, a variable rate issue with allowed returns adjusted every few years to market-based levels, the medium-term PECO bonds are the appropriate point of comparison. This comparison between my DCF and risk premium findings indicates a yield spread, or risk premium, that is fully sufficient to reward investors for investing in PECO's equity.

Q: HAVE YOU PERFORMED ANY OTHER CHECKS ON THE REASONABLENESS OF YOUR DCF FINDINGS?

A: Yes. The final check of reasonableness that I have performed is one in which my DCF findings are compared with recent required returns on other competing investments. This approach is totally independent of my company specific DCF approach and therefore offers an acceptable method for

investments that I have chosen have associated risks that range from very low to very high levels. If my DCF findings are within reason, they should be similar to required returns on investments in the same risk category as PECO's common stock.

Q: WHAT IS YOUR SOURCE FOR RECENT REQUIRED RETURNS ON INVESTMENTS OF VARYING RISKS?

A: I rely on Moody's Bond Record and the S&P Bond Guide. Both contain implicit required returns of investors on numerous bond issues. These returns are based on actual sale prices of the issues and the expected income stream to maturity from the security.

Q: ARE THE REQUIRED RETURNS SHOWN IN THESE PUBLICATIONS DIRECTLY COMPARABLE TO YOUR DCF FINDINGS?

A: Yes, they are. The required returns are discounted cash flow (DCF) returns calculated from the current price of the bond and the expected income stream (coupon payments and return of the bond's face amount upon maturity), just as my DCF findings for PECO were determined. There is, however, less uncertainty as to the investor-required (expected) return on these bonds, since the coupon amounts and frequency of

payment, as well as the face amount to be returned upon maturity, are contractually specified. The required returns (yields-to-maturity) contained in the Moody's and S&P publications are therefore a more accurate indication of actual investor return requirements than are the DCF returns derived for a common stock.

Q: IS THE INVESTMENT RISK ASSOCIATED WITH PECO'S COMMON STOCK CONTAINED IN THE RANGE OF RISKS ASSOCIATED WITH THE BONDS INCLUDED IN THE MOODY'S AND S&P PUBLICATIONS?

A: Yes. Risks associated with the referenced bonds range from the very low to the very high. The triple-A rated bonds are, for example, among the lowest risk investments available. Their low risk is apparent from the fact that recent required returns on triple-A bonds are near 10.4% which is only 30 basis points more than the 10.1% return currently required on long-term Treasury securities.

On the other hand, bonds rated triple-C (or Caa) are among the most risky of all investments. Moody's describes these bonds as being of "poor standing" and states that such bonds may be in default. S&P similarly states that these bonds are, on balance, "predominantly speculative with respect to capacity to pay interest and repay principal" in accordance with the contractual agreement.

PECO's common equity is more risky than triple-A rated bonds, because of greater uncertainty concerning the amount and timing of the future income stream. However, this uncertainty is less than that associated with the triple-C bonds of a company that is near bankruptcy. While PECO management and the investment community have mentioned the possibility of a dividend reduction, such a reduction would not lead to losses comparable to these faced by the owner of the typical triple-C rated bond. The dividend cut would reduce the level of income to PECO shareholders, but income would continue to be received and a relatively small drop in PECO's stock price would occur. In the case of default on the bond, however, years may pass before the investor can recover even a portion of his investment.

Q: WHAT RISK LEVEL DO YOU ASSOCIATE WITH PECO'S COMMON STOCK?

A: An investor in PECO's common stock currently faces risks that are similar to those faced by an investor in bonds rated between B and CCC (Caa). In my judgment, the uncertainties associated with the regulatory treatment of PECO's Limerick investments, and concomitant uncertainty as to the impact of this treatment on PECO's dividend, are risks similar to those faced by investors in the CCC risk class. Without these uncertainties, an investment in PECO's stock would be significantly less risky.

Other factors considered in my risk classification of PECO include liquidity risks and price volatility. My findings indicate PECO's common equity has lower liquidity risk than most B-rated bonds, i.e., it my be sold at a lower price sacrifice than most B-rated bonds. For example, bonds rated from B to CC currently have a 3% to 5% spread between the bid and ask price. PECO's common equity can, on the otherhand be sold at approximately a 1% price sacrifice.

Comparing PECO's stock price volatility with the volatility of high risk bonds, PECO's stock is again shown to be of lower risk. As previously mentioned, bonds in general (independent of their risk class) have shown greater price volatility than common stocks during the past four to five years.

Q: WHAT RETURN IS CURRENTLY REQUIRED BY INVESTOR IN SECURITIES THAT FALL IN THIS RISK CLASS?

A: Schedule 11 shows graphically the current return requirements associated with various levels of risk. Required returns that correspond to a risk rating of B to CCC range from 14.4% to 16.0%, based on data from Moody's November 1985 Bond Record, and from 14.0% to 15.7% based on S&P's December 1985 Bond Guide.

ANALYSIS?

A: Yes, they are. My DCF findngs of 15.1% to 16.1% fall near the upper end of both Moody's and S&P "required return" range found for PECO's risk class. My findings are therefore fully adequate to compensate PECO investors for the risks they assume.

Q: YOUR FINDINGS ON PECO's RETURN REQUIREMENTS HAVE VARIED DEPENDING ON THE METHOD USED. WHAT IS YOUR POINT ESTIMATE OF PECO's EQUITY RATE?

A: My point estimate for PECO's bare equity rate is 15.60% the mid-point of my DCF range. The DCF, risk premium, and risk/return analyses that I have performed rely on recently recorded stock prices and recent long-term Treasury security and corporate bond yields. Results are, therefore, indicative of investor return requirements during the period, 8/30/85 - 12/13/85, in which these prices and yields were recorded. Due to the previously referenced consensus forecasts for no change in capital costs through 1986, I do not believe an adjustment to my findings for anticipated trends is appropriate at this time.

... the capital markets has, however, made even near-term interest rate forecasts susceptible to large errors. In light of such volatility, I consider the mid-point of my DCF range to be the best current estimate of the Company's bare bones cost of equity in this case. The Commission should, however, consider cost of capital trends as they materialize and modify their findings accordingly at the time for decision in this case.

Q: SHOULD YOUR FINDINGS AS TO PECO's COST OF EQUITY BE ADJUSTED FOR FLOTATION COSTS AND MARKET PRESSURE IN THIS CASE?

A: No. An adjustment of PECO's bare equity rate for flotation costs and market pressure offers an insurance policy to stockholders against unfavorable markets. Premiums on this policy are paid by the ratepayers, but the stockholders are the beneficiaries. Furthermore, this policy pays benefits in the form of higher returns on equity whether or not the effects of unfavorable markets during stock sales, or, dilution, are experienced.

Also, market pressure (positive or negative) will occur at the time of every offering whether or not, an adjustment is allowed. Negative pressure will occur, i.e., market price below that which would otherwise be recorded, without the offering if the supply of PECO shares exceeds demand for these shares. Similarly, the price of PECO shares may exceed that which would otherwise be recorded if demand exceeds supply at the time of offering.

Given the above, a flotation or market pressure adjustment in this case in inequitable and should not be allowed.

Q: WHAT CAPITAL STRUCTURE HAVE YOU FOUND REASONABLE FOR PECO?

A: Due to recent new debt issuances and debt redemptions by PECO, the capital structure contained in Mr. Brennan's prefiled exhibits needs updating. The necessary data is not available at this time, however. I intend to file an addendum to this testimony that contains my capital structure recommendations once the required data are available.

Q: DOES THAT CONCLUDE YOUR TESTIMONY?

A: Yes.

Appendix A

Educational and Professional Summary

INTRODUCTION: Mr. Winter is a Chartered Financial Analyst and has prepared testimony on Cost of Capital and other public utility regulatory issues since 1980.

EDUCATION:

University of Oklahoma, 1965
MA in Mathematics

BS, Southwest Missouri State College, 1964
Major: Mathematics

HONORS RECEIVED:

Cum Laude Graduate
Who's Who Among Students in American Universities & Colleges

EMPLOYMENT:

Operations Research Analyst
Rate Case Division
Office of Public Utilities
General Services Administration
Washington, DC
December 1979 to present.

Program Analysis Branch Chief
Division of Program Planning and Analysis
Department of Health, Education and Welfare
Washington, DC
February 1979 to December 1979.

Operations Research Analyst
Policy and Procedures Division
Public Buildings Service
General Services Administration
October 1976 to February 1979.

Industrial Engineer and Mathematician
Manpower and Cost Control and Research Departments
U.S. Postal Service, Hq.
Washington, DC
June 1968 to October 1976.

PUBLICATIONS: "Single-stage vs. Multi-stage Discounted Cash Flow Analysis for Cost of Equity Determination;" Electric Ratemaking, Vol. 1, No. 5, Oct/Nov. 1982, pp. 27-29.
(Co-authored with David E. Kelley)

"The Discounted Cash-flow Estimate of the Dividend Growth Rate Revisited", (Comment on prior article), Public Utilities Fortnightly, Nov. 8, 1984, pp. 56, 57.

PROFESSIONAL AFFILIATIONS:

The Washington Society of Investment Analysts, Financial Management Association.

PARTICIPATION IN REGULATORY PROCEEDINGS

Mr. Winter has testified on cost of capital issues before the following state commissions and other regulatory bodies: California, Colorado, District of Columbia, Federal Energy Regulatory Commission (FERC), Florida, Illinois, Maryland, Oklahoma, Pennsylvania, and Texas.

GSA STATEMENT No. 1

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

Exhibits of

PHILIP R. WINTER, CFA

Cost of Capital

on Behalf of the Federal Executive Agencies
General Services Administration

General Services Administration (PUR)
Room 6317
18th & F Streets, N.W.
Washington, DC 20405
(202) 566-1034

January 2, 1986

Schedule 1

COMPUTATION OF PECO's OVERALL COST OF CAPITAL

	% of Total Capital	Effective Cost (%)	Weighted Cost (%)
Long-term debt	***	***	***
Preferred stock	***	10.41	***
Common Equity	***	15.60	***
Total	100.0%		***

*** Actual data on the effect of new debt issuances and debt redemptions on the Company's test year capital structure and overall cost of capital are not available at this time. The above schedule will be completed when data are available.

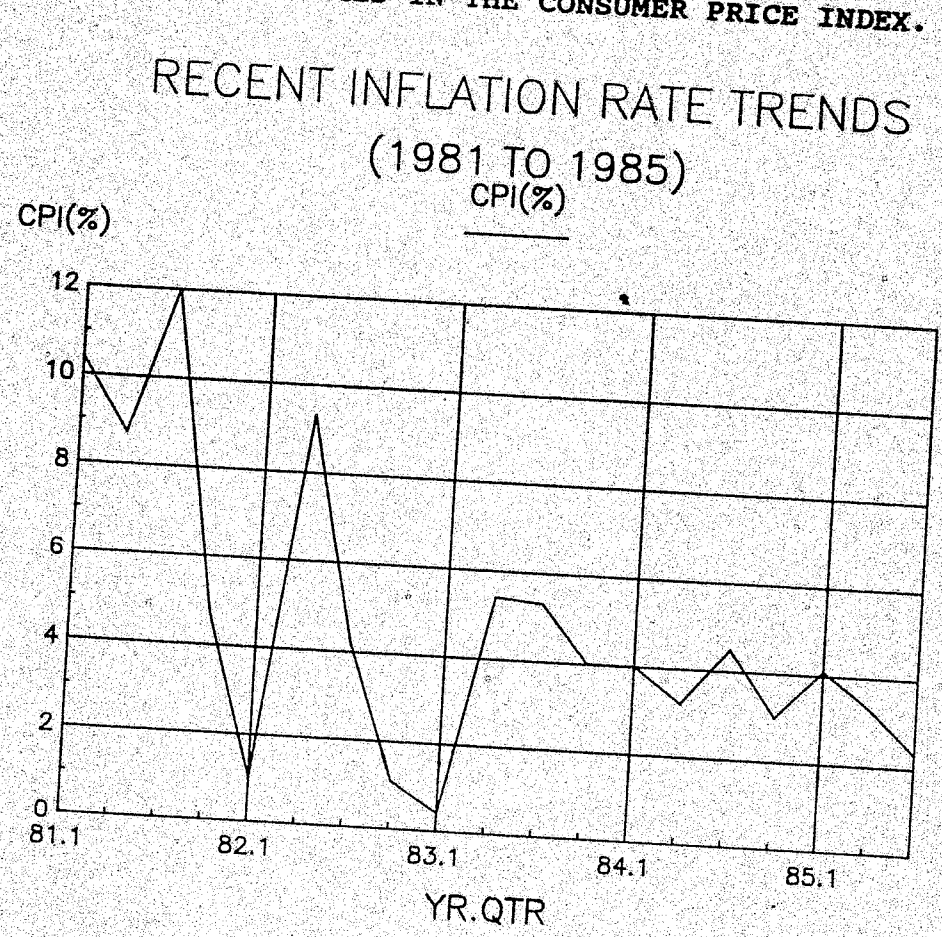
Schedule 2

Estimated Test Year Costs
Pollution Control Notes

Pollution Control Notes:	Amt. Outstdg.(000)	% of Total	Effective Costs (%)	Weighted Costs (%)
5.50%, due 1997	$24,485	4.72	5.02	.24
13 %, due 2010	71,500	13.80	13.38	1.85
11.5%, due 2011	18,500	3.57	13.16	0.47
Floating Rate, 1982 Series A	60,000	11.58	5.65	0.65
Floating Rate, 1982 Series B	40,000	7.72	5.26	0.41
Floating Rate, 1983 Series A	50,000	9.65	5.27	0.51
Floating Rate, 1984 Series A(York)	4,500	0.87	5.07	0.04
Floating Rate, 1984 Series A(Salem)	4,200	0.81	5.07	0.04
10.5%, Series due 2015	245,000	47.28	10.79	5.10
Total Pollution Control Notes	$518,185	100.00%		9.31%

Schedule 3

I. TRENDS IN CHANGES IN THE CONSUMER PRICE INDEX.



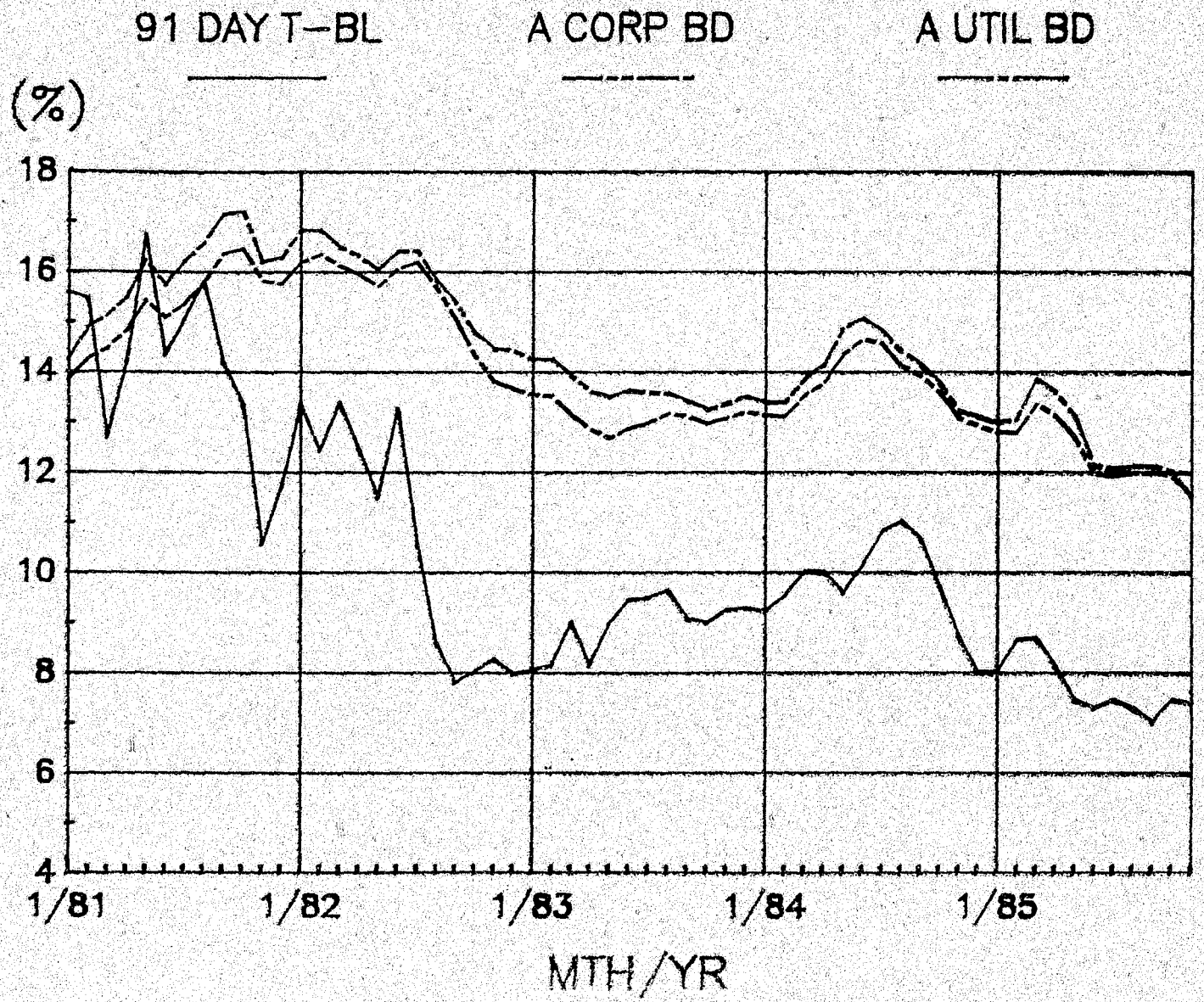
II. FORECASTS OF INFLATION IN CONSUMER PRICES (1985-1986)

	1985 over 1984(%)	1986 over 1985(%)
-L. Meyer & Associates	3.5	3.1
-Evans Economics	3.5	3.8
-Univ. of Michigan M.Q.E.M.	3.5	4.0
-University of California L.A.	3.4	3.6
-Chase Econometric	3.5	3.9
-Value Line	3.5	4.2
-Blue Chip Consensus	3.5	3.7
-Merrill Lynch	3.4	3.4
-Citicorp Information Services	3.5	4.4
-Dr. Walter W. Heller, U.of Minn	3.4	4.0
-Dr. Murray Weidenbaum, Wash. U., St. L.	3.5	4.3

Source: Blue Chip Economic Indicators December 10, 1985; The Value Line Investment Survey, "Selection and Opinion", December 20, 1985.

INTEREST RATE TRENDS

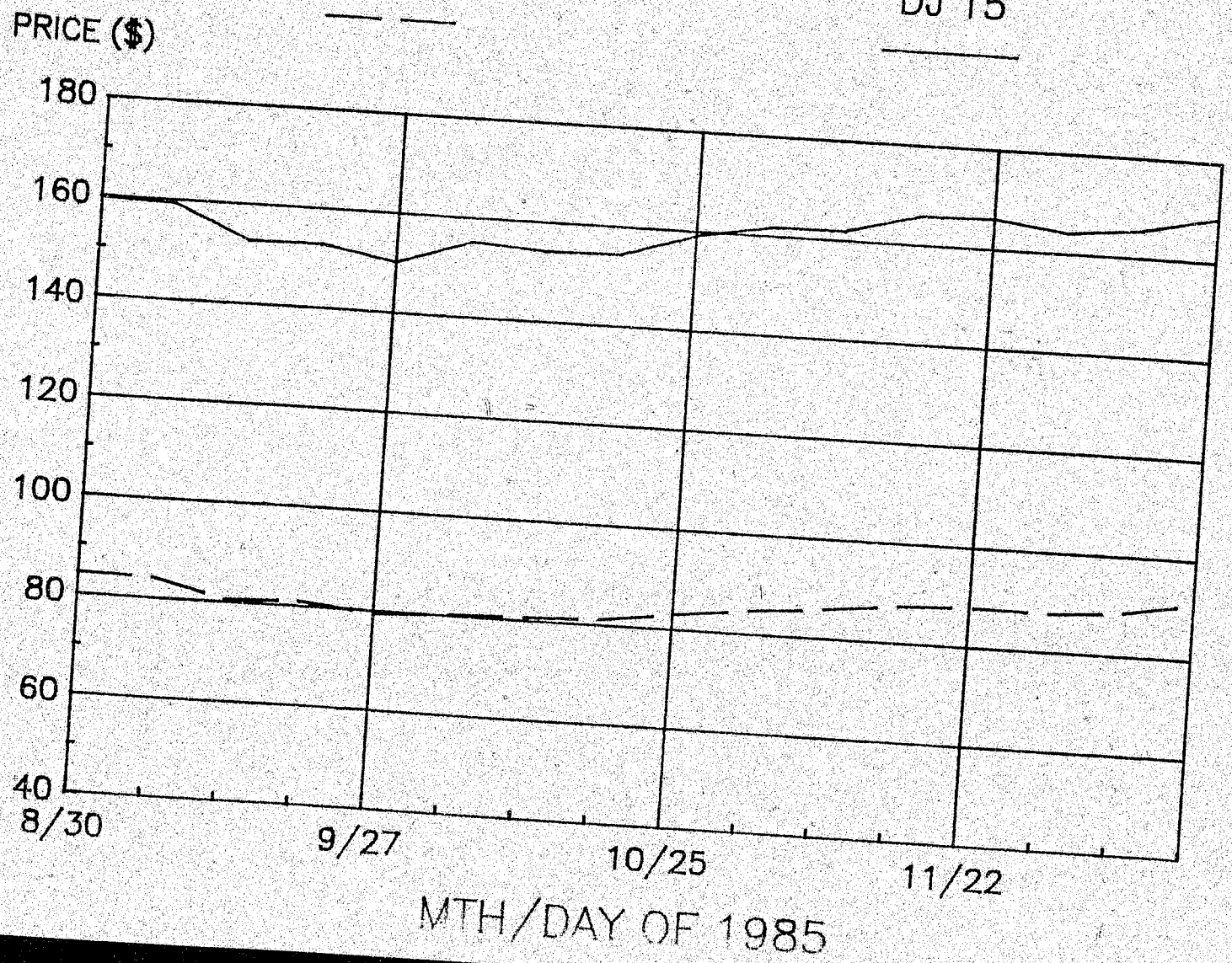
(JAN. 1981 TO NOV. 1985)



Schedule 4

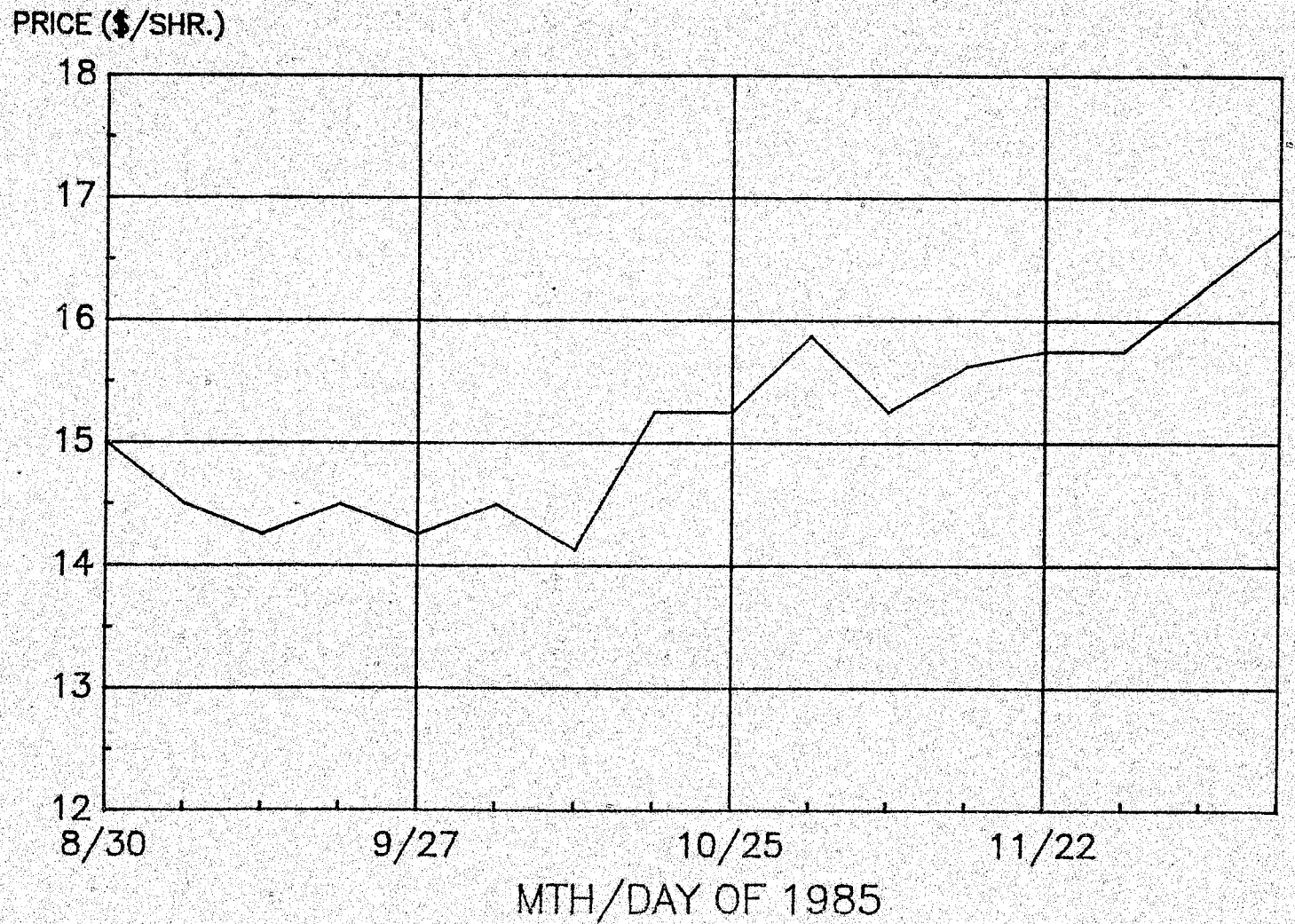
RECENT UTILITY INDEX PRICE TRENDS

AUG. 30 TO DEC. 13, 1985



Schedule 5

PECO'S RECENT STK PRICE TRENDS
AUG. 30 TO DEC. 13, 1985



Schedule 6

Comparison of Net Profit Margins and Return on Equity Trends for PECO, Moody's Electric Utility Index, and Large Corporations 1981-1984

Part I:

	1981	1982	1983	1984
After-Tax Profit Margin (%):				
PECO	11.4	12.7	15.0	16.5
Moody's Electric	11.0	11.9	13.3	12.7
Large Corporations	4.9	4.1	4.5	4.9
Return on Equity (%):				
PECO	11.4	12.3	12.5	14.1
Moody's Electric	11.9	12.6	13.7	14.5
Large Corporations	14.0	11.0	11.5	13.2

Source: Data on PECO and Moody's Electrics are from the Value Line Investment Survey, dated September 27, 1985 and June 7, 1985, respectively. Data on large corporations are from Business Week, dated March 15, 1982; March 14, 1983; March 21, 1984; and March 22, 1985.

Part II:

Fundamental Factors Contributing to Returns on Equity for PECO in 1983 and 1984 and for Moody's Electrics in 1984.

	Tot. Cap. Turnover		Leverage		Pre-Tax Prof. Margin		1-Tax Rate		ROE
PECO (1983)	.3841	x	2.6316	x	.1594	x	.776	=	.125
PECO (1984)	.3797	x	2.7174	x	.1728	x	.791	=	.141
Moody's Electrics (1984)	.4847	x	2.4390	x	.1887	x	.650	=	.145
%Difference (PECO vs Moody)	-21.66		+11.41		-8.43		+21.69		-2.76
%Difference (PECO 1984 vs 1983	-1.15		+3.26		+8.41		+1.93		+12.8

Source: All calculation are based on actual data contained in The Value Line Investment Survey, "Ratings & Reports", June 7, 1985 and September 27, 1985.

Schedule 8

ALGEBRAIC RELATIONSHIP ASSUMED IN THE DCF MODEL

(1) Infinite Model: $P_o = D_1/(1+K_1)+D_2/(1+K_2)^2+ \ldots +D_n/(1+K_n)^n + \ldots$

Where: P_o is the current price of the security
D_i is the dividend received in year i, i = 1 to oo.
K_i is the investor discount rate in year i, i=1 to oo.

Under simplifying assumptions of constant dividend growth and investor discount rate, this method becomes:

(2) $$P_o=D_o(1+G)/(1+K)+D_o(1+G)^2/(1+K)^2+\ldots+D_o(1+G)^n/(1+K)^n+\ldots$$

Where: D_o is the current dividend
G is the assumed constant dividend growth rate.
K is the assumed constant investor discount rate.

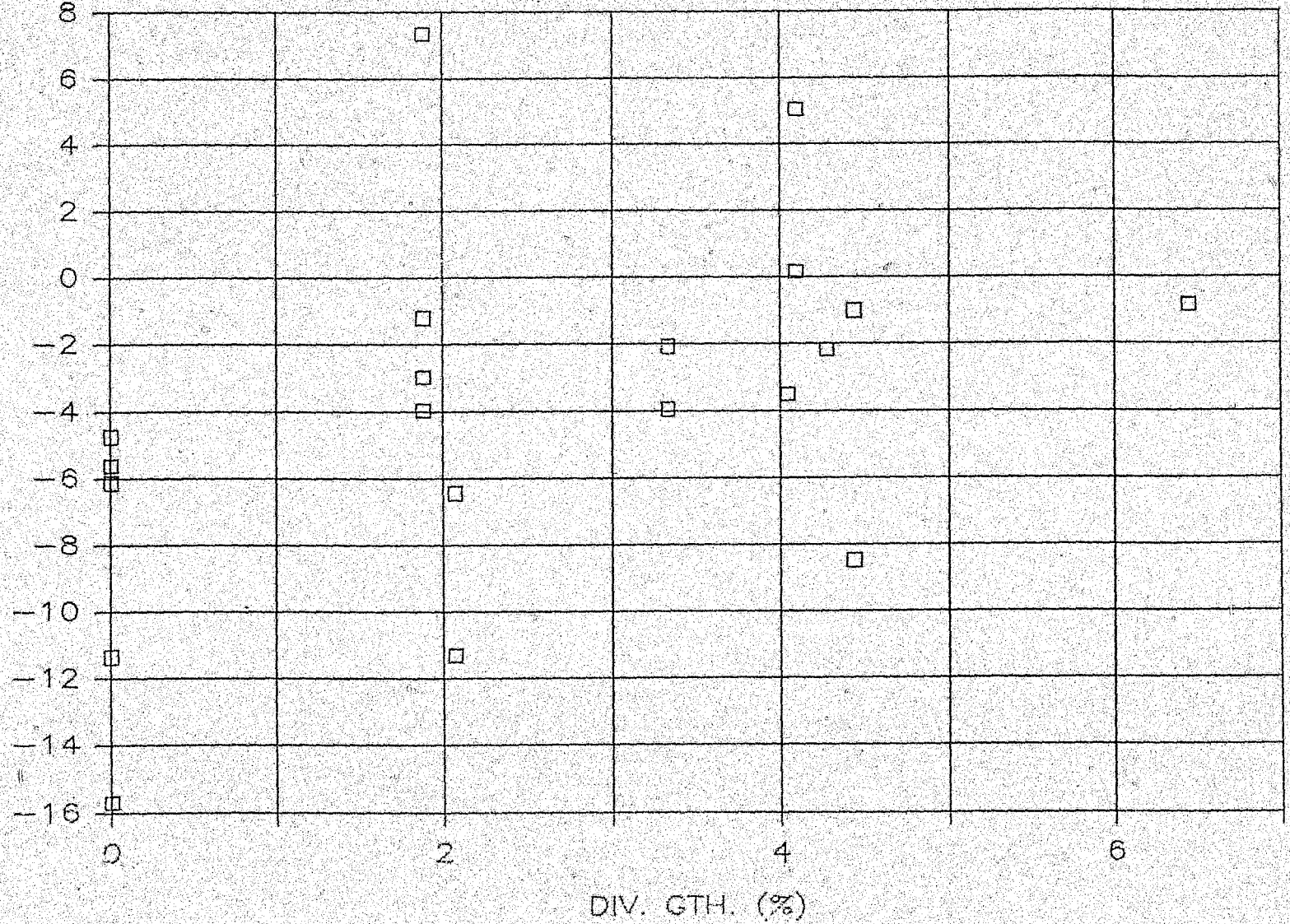
(3) Finite Model:

$$P_o=D_o(1+G)/(1+K)+D_o(1+G)^2/(1+K)^2+\ldots+D_o(1+G)^n/(1+K)^n+P_n/(1+K)^n.$$

Where: P_n is expected stock price at end of a n-year finite period, and constant dividend growth and investor discount rate are assumed.

PECO'S PRC. & DIV. GTH. HISTORY

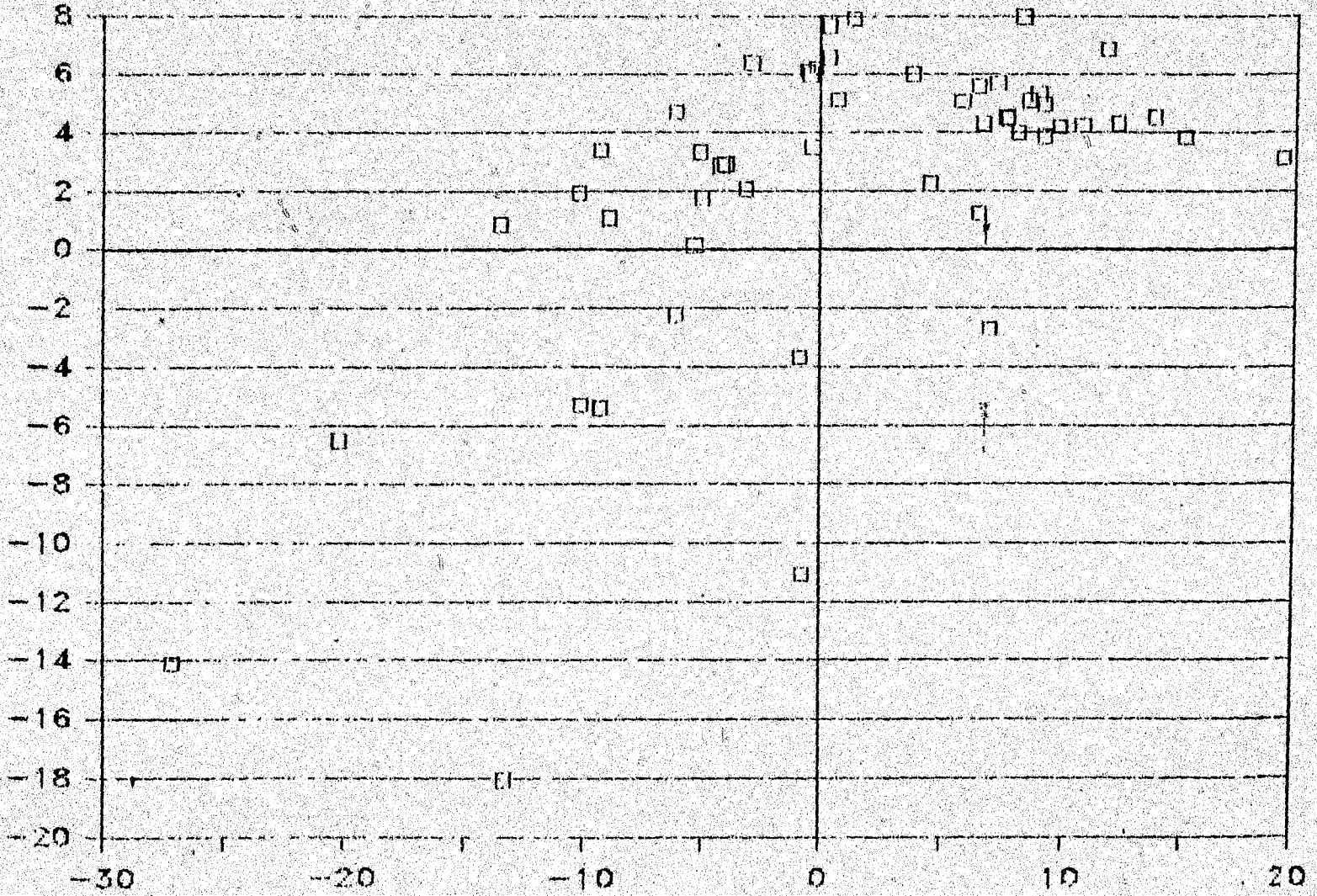
1961 TO 1985 (5-YR. HOLDING PERS.)



Schedule 9

MOODY'S UTIL PRC & DIV GRWTH HIST.

FOR 5-YEAR PERIODS 1929-1984

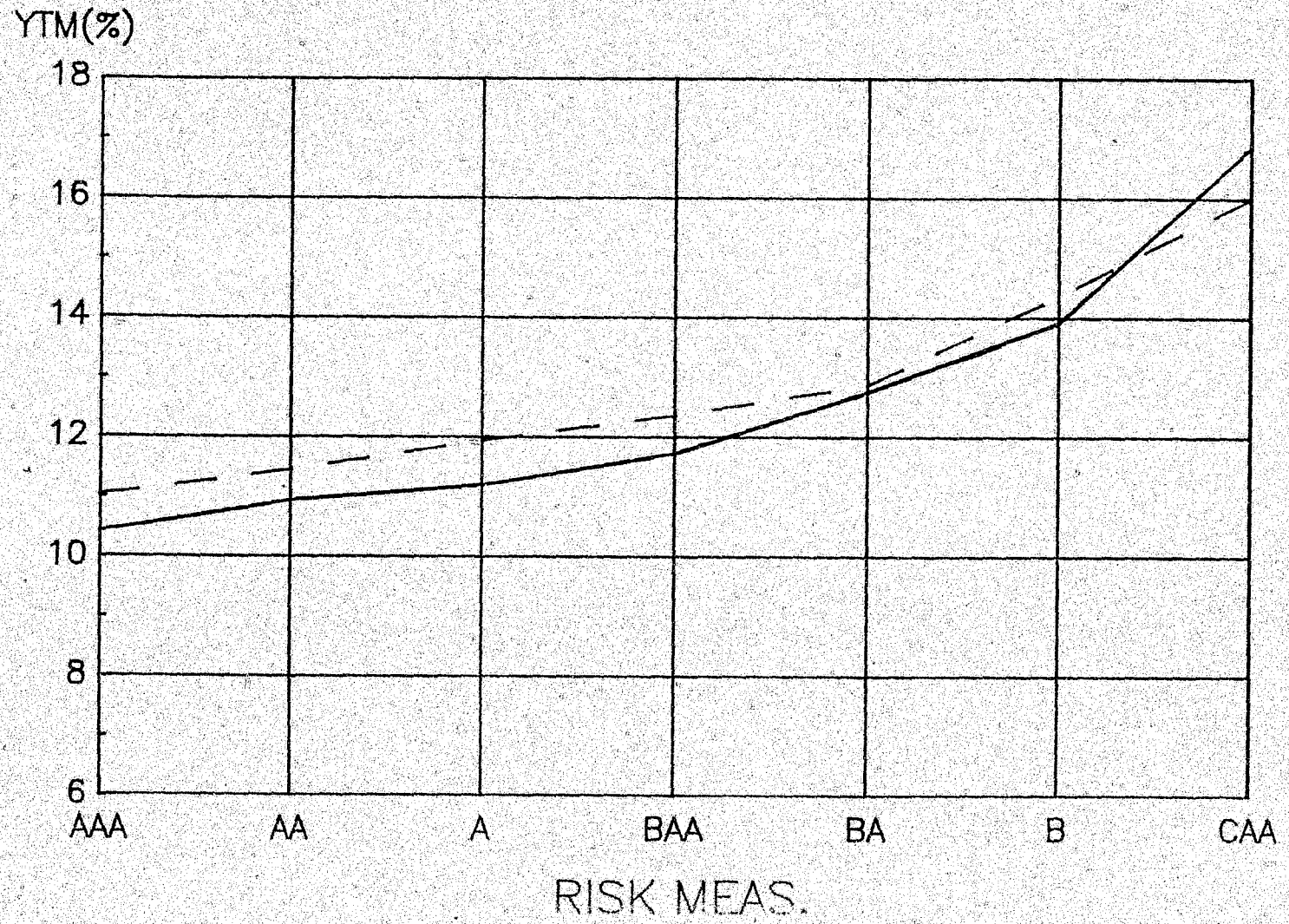


Schedule 10

REQ. RETURN VS RISK

(OCTOBER 1985)

MOODY'S DATA — — S & P DATA ———



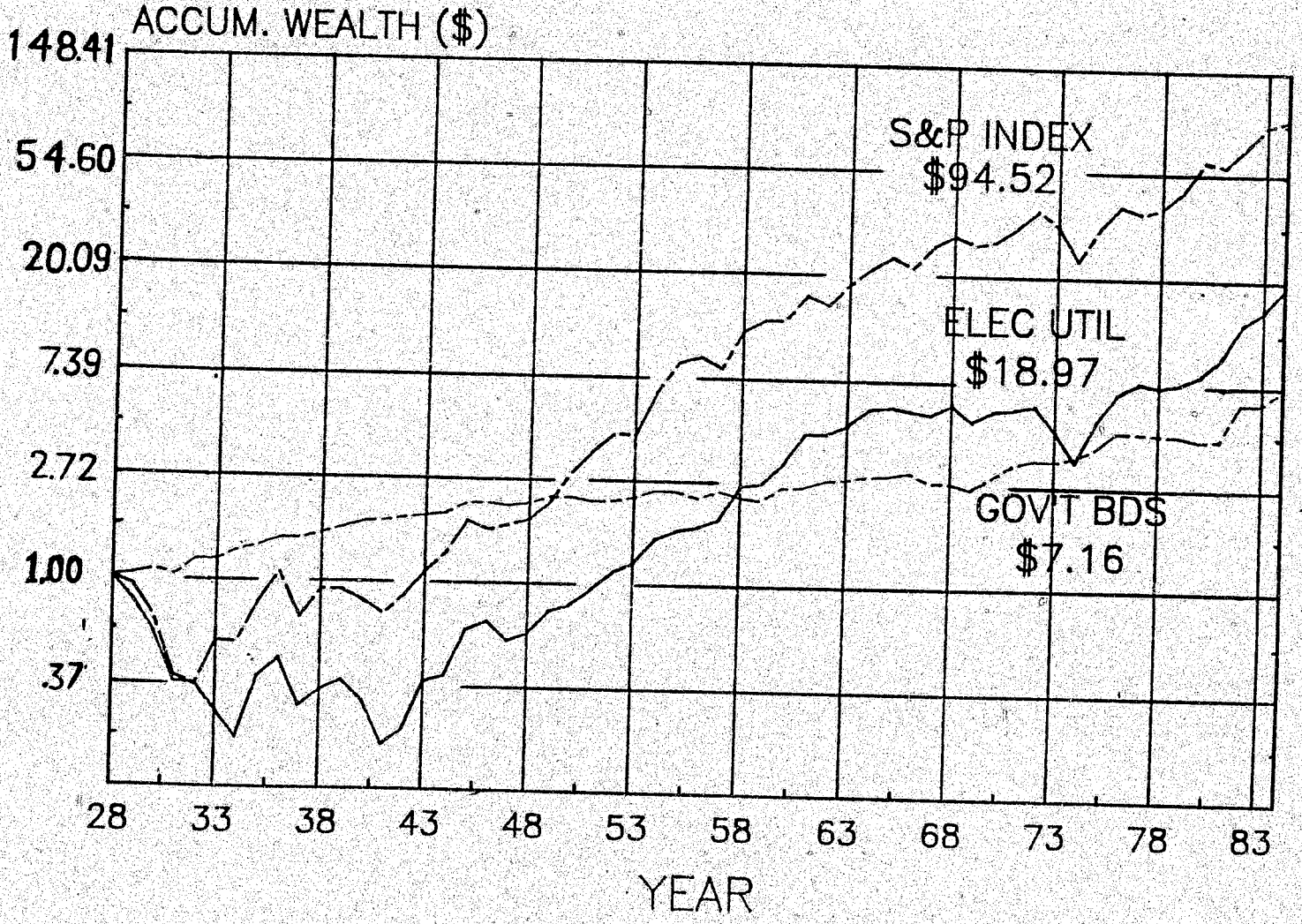
Schedule 11

Schedule 12

MAJOR INVESTMENT FIRMS' RECENT
SHORT-TERM GROWTH EXPECTIONS FOR PECO
DIVIDENDS AND EARNINGS

	Expected Average Annual Growth Rates (%)	
	Dividends	Earnings
Value Line	2.2	1.4
Prudential-Bache	0.0	0.0
Merrill Lynch	1.8	-2.3
Salomon Brothers	1.0	2.0
Duff and Phelps	0.0	1.9
E.F. Hutton	0.0	0.0
Dean Witter	2.0	2.5
Average	1.0%	0.8%

ACCUMULATED WEALTH FROM $1.00 INVESTED
AT THE BEGINNING OF 1929



Schedule 13

FEDERATION OF JEWISH AGENCIES OF GREATER PHILADELPHIA
226 SOUTH SIXTEENTH STREET • PHILADELPHIA, PENNSYLVANIA 19102 • (215) 893-5653

BENNETT L. AARON
President

December 20, 1985

RECEIVED
JAN3 1986
SECRETARY'S OFFICE
Public Utility Commission

Jerry Rich, Secretary
Penna. Public Utilities Commission
P. O. Box 3265
Harrisburg, PA 17120

RE: Penna. Public Utility Commission
v. Phila. Electric Co.
Docket #R-850152

Dear Mr. Rich:

It has come to my attention that the Federation of Jewish Agencies of Greater Philadelphia is a member of the Utility Users Commission of Philadelphia, Inc. formed by the Building Owners and Managers Association. This is to inform you that the Federation of Jewish Agencies of Greater Philadelphia is withdrawing as a member of the Commission since our participation creates the erroneous impression that the Jewish community of Philadelphia is taking a formal position on issues relating to the Limerick facility.

DOCKETED
JAN 7 1986

Sincerely,

Bennett L. Aaron

DOCUMENT FOLDER

BLA/mz

cc: Honorable Joseph Matuschak, ALJ
Marlene R. Chestnut, Esq. PUC Trial Staff
David Wersan, Esq., Office of Consumer Advocate
Mark Widoff, Esq., Utility Users Com. of Phila., Inc.
Walter R. Hall, II, Esq., Phila. Electric Co.