PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit MJB 1 – 8

Witness: Michael J. Berish
Docket No. R-00943271

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit MJB 1

Introduction to the Budget Manual

Chapter 110

INTRODUCTION

PURPOSE OF MANUAL

The purpose of the Budget Manual is to enhance a cost area's ability to prepare and use budgets by:

- Providing an understanding of the cost management process by which the Company plans and controls its expenditures.
- Showing the relationships of all budgets that a cost area might be asked to prepare and how those budgets impact the Company's forecast of earnings.
- Providing a common reference source for all budget instructions.
- Serving as a vehicle to identify potential improvements in the budget process.
- Soliciting user comments or suggestions as to how the overall budgeting and cost control process can be improved.

The development of the Budget Manual and improvements to the budgeting process will be an ongoing activity. As modifications are made, updates to certain sections and/or pages will be mailed to the cost area head for inclusion in the cost area's Budget Manual.

ITEMS INCLUDED IN THE MANUAL

This manual was designed for use as a cost area reference manual. It includes information and instructions concerning budgets that are prepared by many cost areas. Each section of the manual contains information relating to the budget's purpose, important dates for budget preparation, the approval process, instructions for input of data and, if appropriate, explanation of output reports. The instructions included for each individual budget represent general instructions that provide the cost area with the information needed to input cost area data to the budget system. Not included in this manual are any supplemental budget instructions covering documentation required for department approval.

A brief summary of the topics included in each section follows:

Section 1 - General

Table of Contents - Chapter Index

Cost Management Process

This section describes ten components that serve as a framework for effective cost management. The Cost Management Process is included in this manual to emphasize that preparation of the budget is only one component of cost management. Each cost area must address all of the components to enable the Company to fully meet its goals.

Integration of Budgets

Cost areas develop budgets that serve as their operating plan for the coming year. Many managers are not aware of the interrelationship of each budget to one another or to the overall Corporate Operating Budget. This section explains these relationships both graphically and through narratives.

Current Supplement

This section contains certain loading rates and other critical budget information that will change on an annual basis. This section also contains the current year's timetable of when certain budgets are to be submitted.

Section 2 - Payroll Budget

The payroll budget (part of the Budget Information System - BIS) is used to provide an estimate of the number and job classification of full-time and part-time employees required during the budget year as well as the level of planned overtime. This data is used to calculate each cost area's total payroll budget.

Cost areas also enter employee levels or manhour requirements on a monthly and functional basis by account classification (expense, clearing, capital or other). This data is used to determine the cost area's monthly budget by user determined functional designations.

Section 3 - Other Operating Costs Budget

This section includes instructions on the other half of the Budget Information System (BIS). Other Operating Costs include all costs except payroll costs charged by a cost area to expense and clearing accounts.

Section 4 - Vehicle/Leased Equipment Budget

This budget is used to identify all vehicles and other equipment that the Company elects to lease through a third party leasing company rather than directly purchase. The cost of leased equipment represents a large portion of the rental expense included in the Other Operating Costs budget.

Section 5 - Construction Budget

The Construction budget is used to identify Transmission, Distribution and Generation projects planned for construction or purchase during the next five years.

Section 6 - Office Furniture & Equipment Budget

This budget identifies the cost of chairs, desks, partitions, calculators, etc. having a unit cost qualifying the purchase to be accounted for as a capital item.

Section 7 - Tools & Equipment Budget

Included in this budget is the cost of shop, garage, construction, power plant and general tools and equipment. The unit purchase price of each item must exceed the amount needed to qualify the item for capital treatment.

Section 8 - General Buildings Budget

New buildings or additions to Company-owned or leased buildings planned for construction or purchase within ten years are included in this budget.

Section 9 - Cash Budget

The Cash budget is used to identify the Company's financing requirements for the budget year. Most of the input is derived from data entered in either the Capital or Operating budgets. This section concerns transactions that affect cash receipts and disbursements that are not directly included in the Capital or Operating budgets.

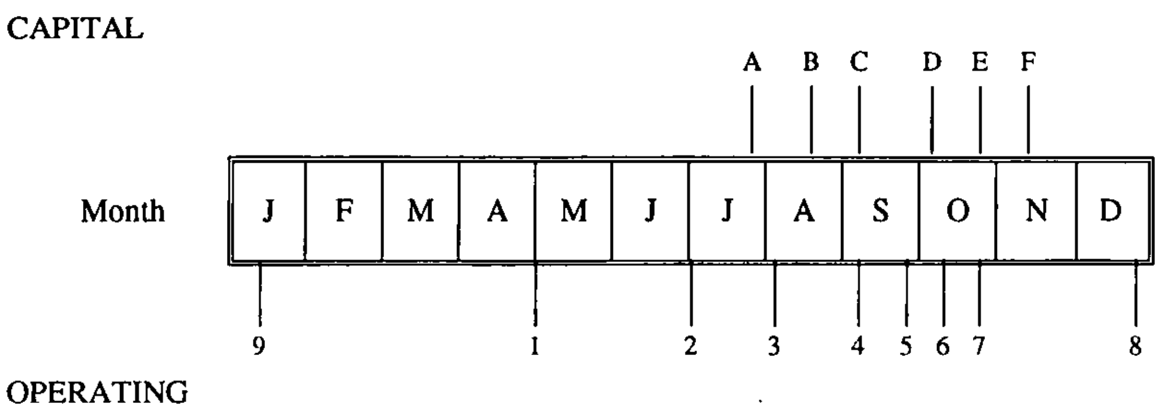
Appendices

This section includes the following general information:

- Cost Area Listing - Shows valid cost area name and number.
- Budget Item Codes and Description - Provides list of valid budget item codes and brief description of items included under each code.
- Glossary of Terms - Brief definition of terms used in the manual.
- Subject Index - Index showing chapter and page number by subject.

GENERAL BUDGET TIMELINE

The following is a general timeline indicating the approximate dates that budget information is supplied to cost areas and due dates for submittal to corporate management. The specific dates are included in the Current Supplement section. Each department may schedule various dates needed for intra-departmental approval prior to the corporate due dates. More detailed timelines for specific budgets are included in each respective budget section.



CAPITAL BUDGET

A. Deadline for submission of projects to System Planning for inclusion in the next year's construction budget.

   Deadline for submission of decision packages for inclusion in the ten-year General Building budget.

B. Deadline for submission of items to be included in the Tool and Equipment budget and Office Furniture and Equipment budget.

C. Due date for submission of changes to the Vehicle/Leased Equipment budget.

D. Due date for submission to Treasury a list of transactions that affect cash and are not directly included in the Capital or Operating budgets.

E. Construction budget sent to CMC for review.

F. Construction budget submitted to the Board of Directors for approval.

OPERATING BUDGET

1. Manhours worked tables issued by Financial Planning. Cost areas may begin entering functional manpower data.
2. Previous twelve-month history data for Other Operating Costs sent to cost areas.
3. Date of estimate for Payroll budget purposes.
4. Due date for submission of Payroll budget to Financial Planning.
5. Due date for submission of Other Operating Costs budget to Financial Planning.
6. Payroll budget submitted to CMC for approval.
7. Other Operating Costs budget submitted to CMC for approval.
8. Total Operating Budget sumitted to CMC for approval.
9. Presentation of Operating Budget to Board of Directors (January of following year).

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit MJB 2

Specialized Data Provided For The Operating Budget

Specialized Data Provided For the Operating Budget

Staff Group	Data Provided
Rates & Market Research	Sales Electric Revenues (Rate, Fuel and Energy, Surcharge) Other Operating Revenues (Forfeited Discounts) Unbilled Sales and Revenues
Fuels Department	Fuel Prices Fuel Consumption Expense
Nuclear Fuels	Amortization Nuclear Fuel Financing Cost of Nuclear Fuel in Reactor Spent Fuel Disposal Cost
System Operating	Station Loading Purchases (Interchange & Other) Sales (Interchange) *Capacity Receipts/Charges* Non-Traditional Bulk Power Sales
Compensation System	Wage Rate Increases (Management/ Union)
System Planning	Construction Budget Property Additions & Retirements
Controller's Division-Depreciation	Depreciation Expense
Controller's Division-Tax Section	Income Tax Provision (Federal & State) Deferred Taxes (Federal & State) Investment Tax Credit Deferrals Investment Tax Credit Amortizations Taxes Other Than Income
Controller's Division-Regulatory Accounting	Decommissioning Provision
Payroll Administration/Employee Benefits	Employee Benefits Payroll Taxes

Staff Group	Data Provided
Transportation	Fleet Lease Data
Division Operations-Administration	Charitable Contributions
Technology & Energy Assessment	External Research Budget
Insurance	Fire & Casualty Insurance Premiums
Plant Accounting	Meter & Transformer Purchases
Controller's Division-Accounting	Uncollectible Accounts
Treasury	Cash Budget
Finance	Financing
Pennsylvania Electric Co. (Operator-Keystone & Conemaugh)	Keystone & Conemaugh Operating Expenses
Financial Planning	Other Operating Revenue (Excl. Forfeited Discounts) Energy Clause Factors Fuel Adjustment Factors Unbilled Energy Revenue Miscellaneous Receipts (Corporate Cost Area) Miscellaneous Expenses (Corporate Cost Area) Allowance For Funds Used During Construction Income Tax Credits (In Other Income & Ded.) Income From Subsidiaries (In Other Income & Ded.) Other Income-Net (In Other Income & Ded.) Interest Expense Preferred Stock Dividends Wages & Benefits (Total and To Expense) Fleet Lease Payments Deferred Susquehanna Operating Costs Deferred Susquehanna Return Costs

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit MJB 3

Cost Areas – September 1, 1994

COST AREAS
September 1, 1994

Number	
001	CHAIRMAN
005	Auditing
020	Executive Vice President and Chief Operating Officer
280	Public Affairs
205	Office of General Counsel
220	Corporate Communications
221	Reprographic Services
222	Special Office of the President-Susquehanna
	FINANCIAL
	Department Administration and Finance
100	Department Administration
195	Finance
105	Controller
110	Corporate Accounting
115	Financial Reporting
120	Plant Accounting
* 106	Decommissioning
190	Treasury
191	Treasury Operations
192	Payroll
170	Procurement
180	Materials Management
	INFORMATION SERVICES
140	ISD Administration
141	Information Solutions
144	Technology Development
145	Corporate Telecommunications
147	Consulting Services
150	Computer Services
	HUMAN RESOURCE & DEVELOPMENT
230	Administration
235	Management Development & Training
240	Placement & EEO
245	Compensation Systems
246	Employee Benefits
260	Personnel Relations
270	Safety and Health Services
275	Union Relations
285	Corporate Security
	NUCLEAR DEPARTMENT
	Nuclear Management and Support
300	Sr. Vice President-Nuclear
307	Nuclear Quality Assurance
309	Nuclear Safety Assessment
356	Nuclear Information Services
380	Nuclear Regulatory Affairs

Number	
	NUCLEAR DEPARTMENT (Cont'd)
	Nuclear Engineering
301	Vice President-Nuclear Engineering
310	NSSS Systems
311	BOP Systems
312	Electrical / I&C Systems
313	Computer Systems
314	Programs & Testing
320	Systems Analysis
321	Engineering Technology
322	Maintenance Technology
323	Operations Technology
326	Nuclear Fuels Engineering
327	Economics & Contracts
360	Modification Design
361	Modification Installation
362	Project & Modification Services
363	Nuclear Configuration Management
386	Nuclear Records
387	General Office Administration
388	Planning and Cost Services
389	Department Support
	Nuclear Operations
303	V.P. - Nuclear Operations
330	Nuclear Maintenance
336	Plant Scheduling
337	Effluent Management
338	Site Support
339	Health Physics
340	Chemistry
346	Nuclear Security
350	Nuclear Operations
370	Nuclear Training
376	Nuclear Procurement
* 390	Nuclear Fuel
* 391	Cowanesque Reservoir
	SYSTEM POWER & ENGINEERING
	Power Production & Engineering
610	VP & Technical Support
612	Operations Support
	Fossil Plant Engineering
615	PP&E-Administration
621	Drafting Services
622	Production
624	Fossil Fuels
630	Montour
631	Sunbury
632	Martins Creek
* 634	Keystone
* 635	Conemaugh
639	Brunner Island
640	Combustion Turbines
642	Holtwood
644	Wallenpaupack Hydro
652	Mechanical Tests
653	Chemical Laboratory
	Other SP&E
500	System Power
514	Environmental Management
* 569	Merrill Creek Project
	Bulk Power Engineering
519	Bulk Power Engineering Administration
520	Scheduling, Siting and Surveying
526	Technical Services
527	Transmission Engineering
531	Substation Engineering
541	Design Drafting
546	Tech. Records & Systems
570	Facilities Management

* Charges to these cost areas are non-discretionary, and are not included in Departmental O&M budgets. These cost areas have no employees.

September 1, 1994
(Continued)

Number	
	SYSTEM POWER & ENGINEERING (Cont'd)
	Other SP&E (Cont'd)
605	System Planning
	System Operation
660	Administration
661	Division System Operations
662	Bulk Power System Operations
663	Protection and Operations Support
664	Electrical Test/SFC-Admin. & Maint.
665	Electrical Test-Protection & Control
666	Electric Tests-Radio Communications Services
668	Power Management System Applications
669	Cost and Performance
* 699	Direct Cost of Power
	Construction
550	Administration
551	Construction - PP&E
552	Construction - Division Operations
553	Construction - Nuclear
555	Construction Services
	DIVISION OPERATIONS
700	Department Administration
701	Division Operations Resources
703	SIGHT
702	Rates & Market Research
704	Marketing & Economic Development
705	Customer Service
707	Customer Contact Center
730	Division Operations Services
731	Div. Oper. Training Center
733	Metering Services
780	Transportation Services
781	Tech. Support-Trans. Services
791	Allentown Garage
792	Scranton Garage
794	Montoursville Garage
795	Harrisburg Garage
796	Lancaster Garage
798	Equipment Garage
	Distribution Office
800	Distr. Systems & Admin.
801	Distr. Standards
802	Distr. Engineering & Drafting
803	Real Estate & Right of Way
805	System Shops
806	Distr. Operations & Maintenance
	Lehigh Division
710	Administration
711	Building Services
	Customer Service
719	Headquarters
712	Division Metering
715	Allentown Area
716	Bethlehem Area
717	Buxmont Area
718	Pocono Area
	Marketing & Economic Development
910	Headquarters
915	Allentown Area
916	Bethlehem Area
917	Buxmont Area
918	Pocono Area
	Distribution
810	Distr. Services & Admin.
811	Temporary Line Crews
815	Allentown Area
816	Bethlehem Area
817	Buxmont Area
818	Pocono Area
819	Technical Section

Number	
	Northeast Division
720	Administration
721	Building Services
	Customer Service
729	Headquarters
723	Honesdale Area
724	Scranton Area
726	Wilkes-Barre Area
728	Hazleton Area
	Marketing & Economic Development
920	Headquarters
923	Honesdale Area
924	Scranton Area
926	Wilkes-Barre Area
928	Hazleton Area
	Distribution
820	Dist. Services & Admin.
821	Temp. Line Crews
823	Honesdale Area
824	Scranton Area
826	Wilkes-Barre Area
828	Hazleton Area
829	Technical Section
	Susquehanna Division
740	Administration
	Marketing & Economic Development
741	Administration
742	Industrial & Commercial
744	Residential
	Customer Service
745	Administration
746	Customer Contacts
748	Division Metering
749	Meter Reading & Service
	Distribution
840	Distr. Services & Admin.
841	Temporary Line Crews
844	Schuylkill Area
845	Sunbury Area
846	Bloomsburg Area
847	Lock Haven Area
848	Williamsport Area
849	Technical Section
	Harrisburg Division
750	Administration
751	Marketing & Economic Development
759	Customer Service
	Distribution
850	Distr. Services & Admin.
851	Temporary Line Crews
855	Harrisburg West Area
856	Harrisburg East Area
859	Technical Section
	Lancaster Division
760	Administration
761	Marketing & Economic Development
765	Building Services
769	Customer Service
	Distribution
860	Distr. Services & Admin.
861	Temporary Line Crews
865	Lancaster East Area
866	Lancaster West Area
869	Technical Section
	COSTS NOT ASSIGNED TO DEPARTMENTS
990	Corporate

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit MJB 4

1995 Budget Preparation Schedule

May 13, 1994

TO ALL COST AREA HEADS:

1995 BUDGET PREPARATION SCHEDULE

Throughout the year, your cost area is required to submit various budgets (e.g., payroll, furniture, operating expenses, etc.) which identify the resources required to accomplish your cost area's objectives and goals. These budgets provide the basis for the corporate Operating & Maintenance (O&M) and Capital budgets. Additionally, individual resource summary budgets (construction, building, vehicles, tools, etc.) serve as input for identifying work requirements for those work groups that provide services to internal clients. For a more detailed explanation of the various budgets prepared within the Company, please see Chapter 130 of the Budget Manual.

Attached is a consolidated schedule for the preparation of both the Capital and O&M budgets. In this schedule, we outline the due dates for all 1995 budgets and will provide you with data, as it becomes available, necessary to complete these budgets. We would ideally like to provide you with a complete budget package all at the same time. However, certain data needed for the preparation of the O&M budget is not available until later in the year, after certain Capital budget items are due to be submitted. Additionally, we will provide any dollar and employee targets as they are determined by CMC.

To prepare these various budgets, a number of "budget packages" are issued throughout the year. Included in the packages are work schedules, input forms, budget history, etc. In past years, preparation schedules for three segments of the Capital budget were issued in February by System Planning. These schedules were for major construction projects (Fossil/Hydro Generation, Transmission & Distribution, General Buildings). This year, new procedures are being implemented and preparation schedules were not issued. The development of project scope, cost estimation and resource planning is still being accomplished under the new procedures.

Another group of work packages are for smaller capital items such as office furniture, tools, and equipment. The requests for these items are attached to this letter. The last major group, but the largest, will be sent out by the end of July and will include initial information for the O&M budget (payroll, other operating costs, vehicles). At the beginning of August, the final package for the Cash budget will be sent out.

Attached to this letter are the following:

1)	Key 1995 Budget Dates	Attachment I
2)	Request for Office Furniture and Equipment Budget Amounts* (Capital Budget)	Attachment II
3)	Request for Tools and Leased Equipment Budget Amounts* (Capital Budget)	Attachment III

** Sent to Departmental Budget Coordinators only, for dissemination of information and preparation of departmental requests.*

Take Care PP&L

A critical factor in developing any of the individual budgets is ensuring that related items from one budget are included whenever appropriate in other budget(s). For example, related maintenance on a new capital project included in one of the various Capital budgets must be included in the O&M budget.

Throughout the budget process, Financial Planning and System Planning work closely with your departmental Budget Coordinators in the development and preparation of budget packages. If you have any questions, suggestions for improvement, or require assistance in preparing your budget(s), please feel free to call us or your Budget Coordinators.

M. J. Berish

M. J. Berish

J. F. Troglione

J. F. Troglione

Attachments

Copies to:
Mr. L. R. Cunningham, TW-19
Mr. A. F. Dreisbach, TW-19
Ms. G. K. Groff, TW-2
Ms. B. M. Kern, N-2
Mr. D. M. Kleppinger, TW-14
Ms. P. A. Kuti, TW-17
Mr. J. J. LaBuda, N-2
Mr. E. L. Lahouchuc, TW-17
Mr. L. J. Marzano, TW-17
Ms. G. S. Master, TW-15
Ms. L. L. Miller, TW-7
Mr. R. J. Miller, A2-3
Mr. P. D. Riley, SSES
Mr. T. C. Roth, TW-16
Mr. R. Salasky, A2-3
Mr. L. Santiso, SNO-Z5
Mr. S. J. Sockel, TW-7

1995 BUDGET
KEY DATES

DATE	BUDGET (*See table on page 2 for list of budget contact persons*)	ACTIVITY
April 29	Construction *(Capital)*	Submission of new Construction Budget Item requests to System Planning
May 3	General Buildings *(Capital)*	Submission of new budget item requests and preliminary decision packages to responsible departments' budget coordinator
June 1	Vehicle/Equipment *(O&M)*	Vehicle/Equipment budget forms distributed
July 7	Payroll/Other Operating Costs *(O&M)*	Financial Planning provides budget preparation materials to Budget Coordinators
July 11	General Buildings *(Capital)*	Submission of final decision packages and changes/revisions to the buildings program to System Planning
July 15	Construction *(Capital)*	Complete manpower estimates for Bulk Power and Distribution Engineering, Construction, Testing, Right-of-Way for projects identified in tentative 1995-96 capital Construction budget
July 17	Payroll *(O&M)*	Budget Information System is updated with the "Date of Estimate" snapshot of employees in each cost area. This is the starting point for budgeting employee adds/drops
August 1	Vehicle / Equipment *(O&M)*	Submission of Vehicle/Equipment budgets to Transportation
	Cash *(Corporate Operating)*	Treasury distributes cash budget forms

DATE	BUDGET	ACTIVITY
August 15	Tools & Leased Equipment *(Capital / O&M)*	Submission of requests to System Planning, including identified leasable equipment
	Office Furniture & Equipment *(Capital / O&M)*	Submission of requests to System Planning, including identified leasable equipment
September 16	Cash *(Corporate Operating)*	Submission of cash flow data to Treasury
October 10	Capital *(Capital)*	Capital Budget presented to CMC for approval
October 14	Payroll / Other Operating Costs *(O&M)*	Deadline for entry of employees and non-payroll costs into the Budget Information System
October 26	Capital *(Capital)*	Capital Budget presented to the Board of Directors for approval
November 14	Payroll / Other Operating Costs *(O&M)*	Operating Budget submitted to CMC for approval

CONTACT PERSONS

Payroll/Other Operating Costs	Mark Woods
Construction General Buildings Tools Office Furniture	Joe Troglione
Vehicle/Equipment	Lou Santiso
Cash	Dale Kleppinger

Attachment II

1995-1996 CAPITAL CONSTRUCTION BUDGET
BI 87002 OFFICE FURNITURE & EQUIPMENT

Funding Guidelines

Funding guidelines will continue to be applied in preparation of the budget and should be used when considering requests for this budget category. These guidelines are intended to result in a mix of projects which are consistent with long-term corporate objectives and are within established funding limits. The following guidelines that were used in preparing the 1994 budget will continue to be used in preparation of the 1995 budget:

PROJECTS TO BE DEFERRED

- Projects which relate to working conditions that address convenience rather than safety or regulatory concerns. ("Is it needed to address an unsafe condition or to maintain or achieve compliance?")
- Replacement projects where timing of failure is a matter of judgement and deferral is judged not to incur a significant risk. ("Is it broken and is it necessary?")
- Projects intended to reduce operating expenses which do not produce a net earnings improvement in one year. ("is there a real, verifiable saving?")

Funding limits for this segment of the budget are based on a minimum reduction of 10-20% from the amount budgeted for 1995 in the "Other" category of the tentatively approved 1995 Capital Construction Budget issued in October, 1993. This is consistent with the funding limits being pursued in other areas of the Capital Construction Budget.

Submission of Budget Requests

All requests should be submitted per instructions provided in Chapter 600 of the Budget Manual. Justification for the item should include some discussion of how it complies with the funding guidelines.

In past years, documentation for items submitted for inclusion in the budget funding varied from department to department. To develop some consistency among the justification and documentation for requests, we have identified five categories to assist in segmenting the items by their intended purpose. They are listed with some examples in Chapter 600, page 3 of the Budget Manual.

In the case of smaller items, they can continue to be grouped based on their compliance with one of the categories.

Included as part of the attachment is a list of "Estimated Unit Costs of Furniture" for use in estimating costs of many commonly-used furniture items.

Lease Items

All items considered leasable should be submitted with the capital requests for this budget category. This will provide the opportunity to have them reviewed for their leasability. Upon review of the submitted items, a response will be made to each submitting department concerning the final disposition of the items.

Each department will be responsible for including the appropriate monthly lease cost in the Operating Budget. Final approval of the Operating Budget with the additional lease costs included will constitute approval to secure the budgeted equipment.

Guidelines for determining what equipment is leasable can be found in Chapter 804 of the Financial Department Manual and Chapters 400 and 420 of the Budget Manual.

Date Required

We will need to receive your budget requests by August 15, 1994 to have adequate time to review and compile them for inclusion the appropriate budgets.

Upon approval of the Corporate Capital Construction Budget in October, the approved allocation for each department for each budget item; (i.e., Office Furniture & Equipment, Tools & Equipment) will be forwarded to each department.

ESTIMATED UNITS COSTS OF FURNITURE AS OF MAY, 1994

DESCRIPTION	ESTIMATED UNIT COST $
OPEN AREA FURNITURE:	
Left Pedestal Desk, 30 x 60	570
Right Pedestal Desk, 30 x 60	570
Double Pedestal Desk, 30 x 60	680
Table, 30 x 60	425
Table, 36 x 60	390
Swivel Desk Chair	370
ConCentrx Operator Chair	440
Side Chair	210
A-style File Cabinet	770
B-style File Cabinet	690
M-style File Cabinet	790
M-3-style File Cabinet	725
L-style File Cabinet	480
L-1-style File Cabinet	380
F-1-style File Cabinet	780
F-2-style File Cabinet	790
F-3-style File Cabinet	680
Coffee Cabinet	420

DESCRIPTION	ESTIMATED UNIT COST $
MGR.'S ENCLOSURE FURNITURE:	
65" High Panel Enclosure	185/lin. ft.
Double Pedestal Desk, 36 x 70	860
Credenza	1,000
Swivel Desk Chair	370
Side Chair	210
Table, 36" Diameter Round	240
Table, 42" Diameter Round	290
Three-high File Cabinet	555
Bookcase	260
CONFERENCE ROOM FURNITURE:	
Table, 42" Diameter Round	290
Table, 48" Diameter Round	345
Table, 60" Diameter Round	525
Table, 60 x 36 Rectangular	390
Table, 96 x 42 x 36 Boat	710
Table, 120 x 48 x 38 Boat	1,255
Chair	210
Chalkless Marker Board, 4' x 6'	275
Chalkless Marker Board, 4' x 8'	340
Tackboard, 4' x 6'	180
Tackboard, 4' x 8'	220
Conference Center	630

COST ESTIMATES FOR FURNITURE TO SUPPORT SPECIALTY EQUIPMENT OR BUDGETING MULTIPLE-TASK WORKSTATIONS

There is a great influx of a variety of speciality equipment such as CRT's, PC's, Word Processing equipment, desk-top copiers, printers, etc. It is not possible to establish a standard workstation since dimensions and wiring requirements of such equipment vary quite a bit. Specification sheets are helpful if they can be obtained from the vendor or manufacturer. Should help in compiling cost estimates be needed, please get in touch with the Supervisor-Facilities Design & Support in the Facilities Management Department.

klh018/df
5/12/94

Attachment III

1995-1996 CAPITAL CONSTRUCTION BUDGET
BI 87003 TOOLS & EQUIPMENT

Funding Guidelines

Funding guidelines will continue to be applied in preparation of the budget and should be used when considering requests for this budget category. These guidelines are intended to result in a mix of projects which are consistent with long-term corporate objectives and are within established funding limits. The following guidelines that were used in preparing the 1994 budget will continue to be used in preparation of the 1995 budget:

PROJECTS TO BE DEFERRED

- Projects which relate to working conditions that address convenience rather than safety or regulatory concerns. ("Is it needed to address an unsafe condition or to maintain or achieve compliance?")
- Replacement projects where timing of failure is a matter of judgement and deferral is judged not to incur a significant risk. ("Is it broken and is it necessary?")
- Projects intended to reduce operating expenses which do not produce a net earnings improvement in one year. ("is there a real, verifiable saving?")

Funding limits for this segment of the budget are based on a minimum reduction of 10-20% from the amount budgeted for 1995 in the "Other" category of the tentatively approved 1995 Capital Construction Budget issued in October, 1993. This is consistent with the funding limits being pursued in other areas of the Capital Construction Budget.

Submission of Budget Requests

All requests should be submitted per instructions provided in Chapter 700 of the Budget Manual. Justification for the items should include some discussion of how it complies with the funding guidelines.

In past years, documentation for items submitted for inclusion in the budget varied from department to department. To develop some consistency among the justification and documentation for requests, we have identified four categories to assist in segmenting the items by their intended purpose. They are listed with some examples in Chapter 700, page 3 of the Budget Manual.

Lease Items

All items considered leasable should be submitted with the capital requests for this budget category. This will provide the opportunity to have them reviewed for their leasability. Upon review of the submitted items, a response will be made to each submitting department concerning the final disposition of the items.

Each department will be responsible for including the appropriate monthly lease cost in the Operating Budget. Final approval of the Operating Budget with the additional lease costs included will constitute approval to secure the budgeted equipment.

Guidelines for determining what equipment is leasable can be found in Chapter 804 of the Financial Department Manual and Chapters 400 and 420 of the Budget Manual.

Date Required

We will need to receive your budget requests by August 16, 1993 to have adequate time to review and compile them for inclusion in the appropriate budgets.

Upon approval of the Corporate Capital Construction Budget in October, the approved allocation for each department for each budget item: (i.e., Office Furniture, & Equipment, Tools & Equipment) will be forwarded to each department.

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit MJB 5

Budget Item Codes

Exhibit MJB 5

BUDGET ITEM CODES

* These codes are not normally used by field personnel.

** These codes can only be charged by Construction and Distribution Department personnel.

*** These codes can only be charged by personnel in the respective service organizations.

May 1993

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit MJB 6

Operating Budget Data – 12-Months Ended September 30, 1995

PENNSYLVANIA POWER & LIGHT COMPANY
Electric Operating Budget
12 Months Ended September 30, 1995
(Thousands of Dollars)

	Total Budget
Operating Revenues	
PUC Customers	
Base Rates	$1,948,941
Energy Cost Rate	322,596
SBRCA	(44,821)
STAS	(5,610)
Total PUC Customers	2,221,106
FERC Customers	
Base Rates	376,700
Fuel Adjustment	(993)
Total FERC Customers	375,707
PJM Power Sales	107,642
Other Electric	53,479
Total Operating Revenues	2,757,934
Operation and Maintenance Expenses (1)	
Fuel	519,358
Power Purchases	263,297
Wages & Employee Benefits	366,658
Other Operating Expenses	362,013
Total O & M Expenses	1,511,326
Depreciation	303,463
Deferred Depreciation	36,374
Regulatory Debits (Credits), net	(36,348)
Income Tax Provision - Federal	193,011
- State	70,411
Deferred Income Taxes	(24,096)
ITC - Deferred	0
- Amortization	(11,037)
Taxes Other Than Income	204,772
Gain from Disposition of Emission Allowances	(486)
Total Operating Expenses	2,247,390
Operating Income	$510,544

(1) Operation and Maintenance Expenses are budgeted by category of expense and not by account.

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit MJB 7

Electric Operating Budget Data by Quarters – 12-Months Ended September 30, 1995

PENNSYLVANIA POWER & LIGHT COMPANY
Electric Operating Budget Data by Quarters
12 Months Ended September 30, 1995
(Thousands of Dollars)

	Total Budget	4th Qtr 1994	1st Qtr 1995	2nd Qtr 1995	3rd Qtr 1995
Operating Revenues					
PUC Customers					
Base Rates	$1,948,941	$495,217	$543,715	$449,026	$460,983
Energy Cost Rate	322,596	75,558	94,168	80,307	72,563
SBRCA	(44,821)	(11,455)	(12,460)	(10,297)	(10,609)
STAS	(5,610)	0	(1,248)	(2,141)	(2,221)
Total PUC Customers	2,221,106	559,320	624,175	516,895	520,716
FERC Customers					
Base Rates	376,700	92,724	98,495	90,382	95,099
Fuel Adjustment	(993)	(416)	(50)	(152)	(375)
Total FERC Customers	375,707	92,308	98,445	90,230	94,724
PJM Power Sales	107,642	27,789	28,889	13,647	37,317
Other Electric	53,479	15,313	15,772	13,360	9,034
Total Operating Revenues	2,757,934	694,730	767,281	634,132	661,791
Operating Expenses					
Fuel	519,358	129,180	148,154	107,286	134,738
Power Purchaes	263,297	63,222	68,688	70,807	60,580
Wages & Employee Benefits	366,658	93,582	89,453	93,885	89,738
Other Operating Expenses	362,013	80,532	89,306	101,558	90,617
Total O & M Expenses	1,511,326	366,516	395,601	373,536	375,673
Depreciation	303,463	71,848	77,205	77,205	77,205
Deferred Depreciation	36,374	6,557	9,939	9,939	9,939
Regulatory Debits (Credits), net	(36,348)	(5,443)	(7,209)	(17,424)	(6,272)
Income Tax Provision - Federal	193,011	54,362	66,467	31,440	40,742
- State	70,411	21,628	23,404	11,049	14,330
Deferred Income Taxes	(24,096)	(7,726)	(8,067)	(1,633)	(6,670)
ITC - Deferred	0	0	0	0	0
- Amortization	(11,037)	(3,027)	(2,670)	(2,670)	(2,670)
Taxes Other Than Income	204,772	50,923	55,810	49,057	48,982
Gain from Disposition of Emission Allowances	(486)	(486)	0	0	0
Total Operating Expenses	2,247,390	555,638	610,480	530,499	551,259
Operating Income	$510,544	$139,092	$156,801	$103,633	$110,532

Exhibit MJB 7

PENNSYLVANIA POWER & LIGHT COMPANY

Exhibit MJB 8

Estimated Cost of the Voluntary Early Retirement Program

Estimated Cost of Voluntary Early Retirement Program

(Million $)

	Age Group 55 - 59	Age Group 60+	Total
For All Eligible Participants			
Social Security Bridge	$43.9	$ 3.3	$47.2
Pension Supplement	26.3	3.0	29.3
Lump-Sum Payment	16.1	6.9	23.0
	$86.3	$13.2	$99.5
For Estimated Participants			
Social Security Bridge	$27.7	$ 2.8	$30.5
Pension Supplement	16.6	2.6	19.2
Lump-Sum Payment	10.2	5.9	16.1
	$54.5	$11.3	$65.8

PENNSYLVANIA POWER & LIGHT COMPANY

Direct Testimony
Statements 1-11

Docket No. R-00943271

Pennsylvania Power & Light Company
Docket No. R-00943271
Index of Direct Testimony

Company Witnesses	Nature of Testimony	Statement	Exhibit
Ronald E. Hill	- Overall Rate Philosophy - Management Effectiveness - Financing Plans - Investment of Nuclear Decommissioning Reserve Fund	1	—
Michael J. Berish	- Operating Budgets - Voluntary Early Retirement Program - SFAS 106 Cost Containment	2	MJB 1-8
Ronald J. Bernini	- Expense Adjustments - Taxes - Cash Working Capital - Fuel Inventories and Reserves - Decommissioning Annuities - Early Window Costs	3	—
Donald S. Hoch	- Depreciation - Levelized Sinking Fund Depreciation	4	DSH 1-2
Douglas A. Krall	- Capital Budget - Pollution Control CWIP - Fossil Plant Lives - Coal Upgrading	5	DAK 1-4
John J. Slivka	- Sales and Peak Demand Forecasts - Annualization of Sales and Revenue - Load Research	6	JJS 1
Joseph M. Kleha	- Cost Allocation - Energy Cost Rate - Special Base Rate Credit Adjustment - Property Held for Future Use	7	JMK 1-3
Oliver G. Kasper	- Pro Forma Revenue Adjustments - Class Revenue Allocation - Rate Design - Proof of Revenues	8	OJK 1-4

Company Witnesses	Nature of Testimony	Statement	Exhibit
John F. Sipics	- Electrical System - Capacity Planning and Reserve Margins - Value of Interruptible Load	9	JFS 1-2
Gerald S. Farber	- Economic Development - Demand-Side Management - Energy Efficiency	10	—
Bernard J. Bujnowski	- Customer and Community Needs Programs	11	—
Paul R. Moul	- Cost of Common Equity - Fair Rate of Return - Capital Structure - Embedded Capital Cost Rates	12	PRM 1
Thomas S. LaGuardia	- Nuclear Plant Decommissioning - Fossil Plant Decommissioning	13	TSL 1-2
Clyde D. Beers	- SFAS 106 Costs	14	CDB 1

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 1

Direct Testimony of Ronald E. Hill

Docket No. R-00943271

Q. Please state your full name and business address.

A. Ronald E. Hill, Two North Ninth Street, Allentown, Pennsylvania 18101.

Q By whom are you employed and in what capacity?

A. I am employed by Pennsylvania Power & Light Company (PP&L or Company) as Senior Vice President-Financial.

Q. What are your responsibilities as Senior Vice President-Financial?

A. I am the chief financial officer of the Company. The functional activities under my supervision include the accounting, finance and treasury activities of the Company.

Q. What is your educational background?

A. I graduated in 1964 from Carnegie Mellon University with a Bachelor of Science degree in Industrial Management. I received a Masters Degree in Business Administration from Lehigh University in 1972 and also attended Muhlenberg College taking several accounting courses. Additionally, I have attended numerous seminars and special courses related to the accounting and finance areas and also attended the Edison Electric Institute's (EEI) Executive Leadership Program.

Q. How long have you been employed by PP&L and in what capacities?

A. I joined PP&L in 1964 as a graduate trainee. Following a two-year leave for military service, I rejoined PP&L as a systems analyst and was named accountant in 1968. From 1968 through 1978, I served in various accounting positions, working principally in the budgeting, financial planning and financial reporting areas. In 1979, I was appointed Manager-Financial Reporting, responsible for all internal and external financial reporting activities. In 1987, I was appointed to the position of Vice President and Comptroller, responsible for all accounting, financial reporting, tax and depreciation functions. On January 1, 1994, I was appointed Senior Vice President-Financial, responsible for all accounting, finance and treasury functions of the Company, and named a member of the Senior Management Committee of the Company.

Q. Are you, or have you been, active in any industry organizations?

A. I am a past member and chairman of the EEI's Application of Accounting Principles and Accounting Research Committees, and am currently a member of the Finance Committee of EEI. I am also a member of the board of directors of Nuclear Electric Insurance Limited, a mutual insurance company providing property and damage insurance for operators of nuclear generating facilities.

Q. Do you belong to any professional organizations?

A. I am a member of the Financial Executives Institute and am also a member of the Institute of Management Accountants.

Q. Mr. Hill, please state the purpose of your testimony.

A. I will address five items in my testimony. First, I will discuss PP&L's overall rate philosophy. Second, I will discuss application of that philosophy and other examples of the Company's effective management of its business. Third, I will identify the sources of data provided to Paul R. Moul to support his testimony regarding a reasonable rate of return in this case. Fourth, I will discuss the Company's plans for additional financing during the future test year. Fifth, I will explain PP&L's request for a clarification regarding the investment of its nuclear decommissioning reserve fund.

Q. What is the Company's overall rate philosophy?

A. Our general approach to ratemaking over the past ten years has been based on two objectives. The first is to maintain rate stability. Since the Susquehanna Unit 2 case, we have undertaken extensive efforts to avoid filing a base rate increase request. Our efforts have included both cost containment programs and revenue enhancement initiatives. I believe that we have been successful in these efforts. PP&L's last retail base rate case was filed with the Commission on July 27, 1984, more than ten years ago. The decision to file the present case was a difficult one and was made only after all other alternatives for maintaining the Company's financial health had been explored.

Our second ratemaking objective has been to pass through to customers the rate impacts of certain significant non-recurring cost savings occurring since our last rate case. For example, in 1986, we passed through the impact of reductions in our federal tax liability using the Income Tax Adjustment or ITA. In addition, we later passed through to customers the cost savings associated with a change in accounting for spare parts inventory at our power plants and the proceeds of a settlement of potential litigation with General Electric Company. These two items were reflected on customer bills through the Special Base Rate Credit Adjustment or SBRCA.

Q. Could you elaborate on the stability of PP&L's rates?

A. As discussed in more detail in the Statement of Reasons, PP&L's average price for electricity has remained essentially unchanged since the Company's last base rate case. After the Susquehanna Unit 2 base rate case concluded in 1985, PP&L's average price for electricity (based upon customer use in that year) was 7.34¢ per KWH. In 1993, the Company's average price was only 7.37¢ per KWH.

PP&L's average price also compares favorably with increases in the Consumer Price Index (CPI). As I indicated, since the Company's last base rate case, its average price has remained essentially unchanged. However, over the same time period, the CPI has increased by more than 30%. In other words, PP&L's average price of electricity has declined substantially in real dollar terms over this period. The Company's total price for electricity also compares favorably with the average prices of other electric utilities in the region.

Q. Please provide examples of the Company's effective and efficient management of its business.

A. Over the past decade, the Company has engaged in extensive efforts to maintain rate stability, control costs, increase revenues, promote economic development and address social issues in its service territory. Taken together, these efforts demonstrate PP&L's commitment to operate an effective and efficient company that provides reliable and economic electric service to its customers.

The Company has implemented a series of cost reduction measures, including reductions in staff levels, elimination of unnecessary functions, a fundamental restructuring at the corporate level and a re-engineering of critical processes. PP&L also has engaged in an extensive refinancing program to reduce its cost of fixed rate securities. The Company has significantly reduced its number of employees and has taken important steps to hold the line on the cost of benefits. A recent example is the Company's Voluntary Early Retirement Program (VERP) which will reduce its workforce by over 600 employees, or about 8%. The Company's VERP is discussed in Mr. Berish's testimony.

The Company has undertaken extensive efforts to operate its Susquehanna nuclear plant both effectively and safely. Susquehanna has had an outstanding operating record since it began commercial operation in the early 1980s. Susquehanna has had an annual capacity factor greater than 70% in every year since 1987, including 1993 which contained an extended refueling outage. In three out of these seven years, Susquehanna's annual capacity factor exceeded 80%. PP&L has calculated that during the 1987-93 period its customers realized energy cost savings of approximately $140 million as a direct result of the Company's ability to operate Susquehanna at a capacity factor above 70%. Susquehanna is recognized by industry organizations and the investment community as an efficient, well-run plant.

On the revenue side, the Company has made a major commitment to economic development to retain existing industry and to attract new businesses to its service territory. In addition to revenue enhancement, these economic development efforts have produced thousands of new jobs in the Company's service territory. While increasing sales, the Company also has remained committed to conservation, load management and demand-side management (DSM) programs designed to promote more efficient and cost effective usage by its customers. The Company's economic development and DSM programs are discussed in Mr. Farber's testimony.

Finally, the Company has maintained and expanded its commitment to those customers who cannot afford to pay their electric bills. As explained in Mr. Bujnowski's testimony, the Company has been and continues to be a leader in this important area and is proposing a number of important new social programs in this case.

While these results are impressive, the Company is committed to additional improvements which will permit it to continue providing the highest quality service at the lowest reasonable cost.

Q. Please describe the financial data that you provided to Mr. Moul for preparation of his testimony regarding fair rate of return in this case.

A. To enable Mr. Moul to prepare his testimony regarding fair rate of return in this case, I provided the following financial data for the historic test year and the future test year:

- Capitalization structure;
- Details of debt securities issued and outstanding and related costs; and
- Details of preferred stock securities issued and outstanding and related costs.

Q. Please describe the Company's plans for raising additional capital during the future test year.

A. In summary, the Company currently plans the following major financing initiatives during the future test year:

- The issuance of $200 million of mortgage bonds at 7.7%, which occurred in October 1994.
- The expected refinancing of $55 million of 9-3/8% series pollution control bonds with a series at an assumed rate of 6-1/2% in June or July 1995.
- The expected retirement of $95.5 million of mortgage bonds, series 9-1/4%, in the June to August 1995 time period.
- The expected issuance of common stock as follows: (1) Employee Stock Ownership Plan (ESOP) - $7 million in December 1994; (2) Public Offering - $100 million in August 1995;

and (3) Dividend Reinvestment Plan (DRIP) - $78 million throughout the year.

Of course, these plans are contingent upon favorable conditions in the financial markets. Depending upon changes in those markets, PP&L may revise these plans.

Q. Please provide some background on the issue of investing nuclear decommissioning reserve funds.

A. The Deficit Reduction Tax Act of 1984 added Section 468A to the Internal Revenue Code (Code). That section provided that a utility will be permitted to take a tax deduction for payments made to a qualified nuclear decommissioning reserve fund. However, the section also limited investments to so-called "Black Lung" investments, which are:

(1) public debt securities of the United States;

(2) obligations of a state or local government which are not in default as to principal or interest; or

(3) time or demand deposits in a bank or insured credit union located within the United States.

Q. Have these "Black Lung" restrictions been changed?

A. Yes. Section 1917 of the Energy Policy Act of 1992 (Act) repealed a portion of Section 468A(e)(4) of the Code which imposed the "Black Lung" restrictions on the investments which a nuclear decommissioning reserve fund could make and still qualify for tax benefits.

Q. Has the Commission addressed these issues?

A. Yes. In a PP&L case, the Commission indirectly discussed restrictions on investments of the Company's nuclear decommissioning reserve fund. On June 9, 1987, PP&L filed a petition with the PUC requesting permission to change the mechanism designed to hold and manage its decommissioning funds from an escrow account to a trust as required by Section 468A of the Code.

On August 20, 1987, the Commission adopted an order at Docket No. P-870231, which stated in part: "That the Pennsylvania Power & Light Company be, and hereby is, authorized to cause funds in the trust account to be invested in the types of investments specified in Section 1.468A-5T(a)(3)(i)(C), of the Internal Revenue Regulations as they may exist from time to time."

In addition, the Commission has granted petitions filed by several other Pennsylvania electric utilities and has permitted those utilities to eliminate the "Black Lung" restrictions on investments of their nuclear decommissioning reserve funds.

Q. Specifically, what is the Company's request in this area?

A. The Company is requesting that the Commission explicitly eliminate the "Black Lung" restrictions on the type of securities in which PP&L can invest its nuclear decommissioning reserve fund. Moreover, the Company requests that the Commission not establish specific criteria for these investments. If the Commission concludes it must establish investment guidelines, PP&L recommends that the Commission adopt a "reasonable person" standard and define "reasonable person" by reference to the "prudent man" standard that is applicable to fiduciaries for pension plans pursuant to Section 404 of the Employee Retirement Income Security Act of 1974 ("ERISA") (29 U.S.C. Section 1104).

The Commission should adopt the ERISA standard because it is defined by statute, has been in existence for 20 years, has wide-spread applicability, is "well-litigated" (i.e., there is an existing body of law that has developed the statutory language) and is widely understood and familiar to investment and trust fiduciaries throughout the country. Its focus on the entire investment portfolio over which the fiduciary has authority and on the nature of the obligations to be satisfied by the invested assets is more rigorous and, therefore, superior to a standard that views reasonableness on an investment-by-investment basis. Its express duty to diversify is fundamental to prudent investment. Its applicability to "fiduciaries" takes into account that a fund involves fiduciaries other than a trustee. The Company has made the same recommendation to the Federal Energy Regulatory Commission ("FERC") in comments to the FERC rulemaking on Nuclear Plant Decommissioning Trust Fund Guidelines at Docket No. RM94-14-000.

If PP&L's request is granted, it would expect to broaden the scope of investments of its nuclear decommissioning reserve fund. The Company anticipates that a broader investment strategy would produce higher returns than are now realized under the current investment restrictions.

Q. Does this conclude your direct testimony?

A. Yes.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 2

Direct Testimony of Michael J. Berish

Docket No. R-00943271

Q. Please state your name and business address.
A. Michael J. Berish, Two North Ninth Street, Allentown, Pennsylvania 18101.
Q. By whom are you employed and in what capacity?
A. I am employed by the Pennsylvania Power & Light Company (PP&L or the Company) as Manager - Financial Planning.
Q. What are your responsibilities as Manager - Financial Planning for PP&L?
A. I am responsible for compiling the corporate operating budget, administering our functional group (cost area) budget control system, preparing financial forecasts and various special studies which require projections of corporate financial performance.
Q. What is your educational background?
A. I graduated in 1967 from the Pennsylvania State University with a Bachelor of Science Degree in Accounting. I also received a Masters Degree in Business Administration from Lehigh University in 1971.
Q. How long have you been employed by PP&L and in what capacities?
A. I joined PP&L in 1967 as a Methods Accountant in the Data Processing Division of the Financial Department where I worked as a computer programmer until 1969. From 1969 to 1973, I was a Systems Analyst and later a Senior Systems Analyst in our Division Operations Department where I was responsible for analyzing clerical systems with a goal of making them more efficient or computerizing them. From 1973 to 1975, I was a Fuel Adjustment Specialist in our System Power & Engineering Department, where my duties were to analyze the fuel costs recovered through the then fuel adjustment clause. In 1975, I was appointed

Supervisor - Financial Planning in our Financial Department, and in 1979 was appointed to my present position.

Q. Are you active in any professional organizations?

A. I am a member of the Budgeting and Financial Forecasting Committee of the Edison Electric Institute. This committee is responsible for examining the latest techniques used in budgeting, long-range financial forecasting and budget reporting.

Q. What is the purpose of your testimony?

A. My testimony will describe the derivation of data used to project the level of operations for the Future Test Year ended September 30, 1995. I will also describe certain adjustments applicable to the Company's Voluntary Early Retirement Program (VERP) and discuss costs applicable to the Statement of Financial Accounting Standards (SFAS) 106, commonly referred to as post-retirement benefits.

Q. How were the Future Test Year financial statements developed?

A. Essentially, the Future Test Year financial statements and data have been based on information which the Company used to prepare its 1994 and 1995 Operating Budgets. Any of the statements pertaining to the Future Test Year which identify data "Per Books" should be interpreted as referring to the hypothetical "books" of the Company reflecting 1994/1995 projected data. This unadjusted "Per Books" data are shown on the B-Schedules of Exhibit Future 1. Generally, this unadjusted projected data has been utilized in responding to the Commission's filing regulations. The various ratemaking adjustments are reflected on the D-Schedules of Exhibit Future 1.

Q. Mr. Berish, I show you eight documents which are marked for identification as Exhibit MJB 1 through Exhibit MJB 8. Were they prepared by you or under your supervision?

A. They were prepared under my supervision. I will be specifically referring to each of the exhibits in my testimony. Several of my exhibits are a part of the Company's "Budget Manual," which covers many aspects of the Company's budget philosophy, guidelines and instructions. Specific sections of the manual have been presented as exhibits, where practical. Because of its size, the manual was not reproduced in its entirety. Exhibit MJB 1 is the Introduction provided in the Budget Manual and describes its contents.

Q. In this filing, the test year is not on an end-of-calendar-year basis. How was data for the test year derived?

A. The Company budgets on a calendar-year basis and has prepared an operating budget for the 12 months ending December 31, 1994. The Company also prepared a monthly budget for the 12 months ending December 31, 1995. The level of operations for the Future Test Year was derived by combining the operating budget data for the last three months of the 1994 calendar year with budget data for the first nine months of the 1995 calendar year.

Q. Mr. Berish, were there any changes made to your budgeted data which are reflected on your Future Test Year B-Schedules?

A. There were two revisions. The last three months from the 1994 Budget, which are the first three months of the Future Test Year, were revised to reflect 1) the requirement to record as a charge against earnings the cost of post-retirement benefits, and 2) an update of the financings planned for the last quarter of 1994.

Q. Can you please explain the post-retirement benefits revision?

A. The Financial Accounting Standards Board issued a ruling, Statement of Financial Accounting Standards 106, which required all publicly held companies to book as current charges benefit costs which would be paid to employees after they retire—post retirement benefits. This requirement was to begin in 1993. Since this would result in a significant charge against earnings, the Company petitioned the Pennsylvania Public Utility Commission (PUC) for the right to defer such costs until our next rate filing. The PUC granted the right to defer. However, this decision was appealed to Commonwealth Court by the Office of Consumer Advocate and was reversed. In mid 1994, the Company charged to expense the previously deferred costs and began booking on a current basis the monthly cost for post-retirement benefits. This action was made after the 1994 Budget was issued but in time to reflect these costs in the 1995 Budget. As a result, the last three months of the 1994 Budget were adjusted to reflect the booking of post-retirement benefits.

Q. How much expense was added to the original 1994 Budget to reflect the booking of post-retirement benefits?

A. An amount of $4.2 million was added to the benefit expense for the last three months of 1994 to reflect the cost of post-retirement benefits.

Q. Has PP&L taken any steps to contain its post-retirement benefit costs?

A. Yes. When SFAS 106 was proposed in 1988, PP&L projected that its annual post-retirement benefit costs would increase from an estimated cash payment of approximately $7 million in 1992 to an accrual under SFAS 106 of about $47 million in 1993. To mitigate this increase, PP&L instituted a contribution plan for retiree medical benefits. Under this plan, the amount that PP&L will pay annually toward medical coverage for retirees is capped at $4,200 for individuals under age 65 and at $1,600 for individuals over 65. These caps are based on the average cost of medical coverage for all retirees, not on the costs incurred by an individual retiree. Therefore, all applicable retirees would have to pay some amount if the average health care cost per retiree exceeds these caps. *These caps apply to all employees who retire on or after* April 1, 1993. This contribution plan reduced the Company's 1993 annual SFAS 106 compliance costs by about 50%.

Q. What other steps has the Company taken to control its health care costs?

A. PP&L has also implemented a number of plan design changes and administrative measures to better control health care costs. These changes began in 1984-1985 with the introduction of precertifications for hospitalization and second opinions for elective surgery. Additional initiatives to control costs have been implemented over the intervening years—examples include: (1) tighter coordination of benefit rules, (2) utilization reviews, (3) special management of high-cost cases, (4) computerized verification of eligibility for charges billed, (5) a negotiated discount program for prescription drugs, (6) smoking cessation and other wellness initiatives, and (7) reduced administrative fees as a result of bidding coverages and negotiating with existing carriers.

In Plan Year 1993, these initiatives produced annual savings of about $1.6 million over and above the discounts that PP&L received from Blue Cross and Blue Shield. Further revisions to the prescription drug program and a change in the Company's major medical carrier yielded additional annual savings of approximately $480,000.

Q. Can you relate what changes were made to the financings for the last quarter of 1994?

A. The financings undertaken throughout 1994 were updated to reflect the rates applicable to securities actually issued. In addition, a $50 million issue of preferred stock at an assumed rate of 7% and a $150 million issue of mortgage bonds at an assumed rate of 7.5%, that were included in the original 1994 Budget, were replaced with a $200 million issue of mortgage bonds at 7.7%. These revisions were due to changes in market conditions and the Company's cash flow throughout 1994.

Q. Would you please explain how the operating budget process is carried out by PP&L?

A. During the fall of each year, we begin preparing a detailed operating budget for the succeeding calendar year. Information used in compiling the operating budget generally can be categorized into two major groups: 1) that which is of a specialized nature (e.g., sales, fuel prices, financing) and is supplied by the staff group having the expertise in forecasting this information; and 2) that which impacts all areas of the Company (e.g., employee levels and other operating costs such as materials, contract work, postage, rents) and is an accumulation of data supplied by all functional groups within the Company. These functional groups are referred to as cost areas.

In developing specialized information, provided by various staff groups, the responsible department makes most of its own assumptions although certain basic corporate assumptions, such as the expected levels of kWh sales, etc., are coordinated between staff groups. Each of the various staff groups then develops its specific phase of the budget. Specialized data from each staff group is coordinated with other staff groups requiring this information to complete their phase of the budgeting process.

In developing the information supplied by all cost areas, each cost area inputs its budget into our on-line mainframe budget system. The budgets are approved electronically in the system by the cost area head, or by his or her designee, recognizing that the cost area head ultimately retains responsibility for the budget. Financial Planning compiles cost area budgets electronically, and this becomes a major input for preparing the overall corporate operating budget.

When cost areas complete their budgets, they are summarized by each department and then reviewed by the president and departmental vice presidents.

Once the approvals of specific phases of the budget have been obtained, a tentative operating budget is prepared. The tentative budget is reviewed with the president and departmental vice presidents with particular emphasis on key financial indicators and customer rates.

After this review, the final budget is prepared and reviewed with the president and Board of Directors. This budget is the key tool used by the cost areas and top management to establish an operating plan for the upcoming year and for measuring actual results against this plan.

Q. You stated that certain specialized data for the budget are provided by other staff groups. Could you tell us specifically what data are provided, and who provides this data?

A. Yes. Exhibit MJB 2 lists the specific staff groups responsible for providing specialized data and describes the data provided by those groups.

Q. You also stated that the remaining data for your operating budget comes from cost areas. What are cost areas, and how many cost areas does PP&L have?

A. Until its recent restructuring, the Company organization was broken down into eight major departments. Each department is subdivided into functional groups referred to as cost areas. Each cost area has an assigned manager who is responsible for all costs incurred by that cost area. Each employee is assigned to a particular cost area. We have approximately 210 cost areas. Exhibit MJB 3 contains a list of the cost areas providing data for the 1994 and 1995 Operating Budgets.

Q. What type of data do they provide?

A. Our cost areas provide a projection of their employee levels for the year. This becomes the basis for projecting total wages. They also provide a budget of their other operating costs.

Q. Could you explain how the budget for wages is determined?

A. Yes. In the spring of each year, a coordinated budget schedule (Exhibit MJB 4) is furnished to each cost area head. The schedule indicates the "Date of Estimate"—the date at which the system takes a snapshot of employees, and their associated wages, in each cost area. Each cost area is required to input any changes from the Date of Estimate starting point. These changes include new hires, decreases due to work force reductions or retirements and changes in salary levels. They are required to enter the month in which these changes are expected to occur and the *job titles of the changes. (Chapter 200 of the Budget Manual provides* step-by-step instructions for cost area input of employee budget changes.) These employee levels are reviewed and approved by each department head in conjunction with the overall budget review.

The budget system automatically calculates a budget for wages based on the starting level of employees and their actual earnings and the employee changes input by the cost areas. Financial Planning then inputs certain costs directly into the cost area budgets, such as accrued vacation paid at retirement and other components based on history and estimates. The system then applies assumed management and bargaining unit wage increases. Financial Planning can then generate a listing of wages by cost area for each biweekly pay period.

The corporate biweekly totals are then adjusted to reflect attrition due to deaths and resignations. Although these particular adjustments are difficult to predict for each cost area individually, they can be reasonably approximated on a total corporate level.

As the cost areas budget their employee levels, they must allocate their available manpower by functional activity. As part of this process, the cost areas designate the applicable accounting to be charged—capital, expense or clearing. Wages identified as expense, and a portion of those budgeted as clearing, ultimately appear on the income statement.

Q. *You mentioned your cost areas budget for other operating costs. What costs fall into this category?*

A. The Company's budgeting system requires budgeting by category of expenditure. We refer to these categories as budget items. Exhibit MJB 5 is a list of our various budget items. The cost areas budget only for those expenditures not identified by an asterisk on Page 1 of Exhibit MJB 5.

Q. How do the cost areas provide these estimates?

A. Cost areas budget their nonpayroll requirements—such as rents, materials and contractors in our on-line, mainframe budget system. The costs are entered by budget item and functional activity, and to the month or months the expenses are anticipated. (Budget instructions for nonpayroll budget items are included in Chapter 300 of the Budget Manual.)

Cost area budgets for payroll and nonpayroll budget items are then approved electronically in the budget system by the cost area head or designee, and then summarized by department for review by the department vice presidents and president. Financial Planning then compiles the budgets for income statement preparation.

Q. As part of the Future Test Year data in the present rate filing, budget expenditures have been provided by account. Do your cost areas also budget by account?

A. No. Our cost areas budget only by category of expenditure (budget items listed in Exhibit MJB 5) and functional activity. We believe it is more meaningful for cost areas to budget and monitor expenditures by category of expense (e.g., payroll, employee expenses, material and supplies) rather than by Federal Energy Regulatory Commission (FERC) accounts. However, to satisfy the requirements for this rate filing, we have allocated expenditures into FERC accounts.

This was accomplished by first allocating operating and maintenance costs budgeted by category of expenditures to FERC accounts where the budget classification was specifically identifiable to a FERC account. These classifications include such expenses as fuel and purchased power. For those budget classifications not identifiable to a specific FERC account, the total remaining budgeted expenditures were allocated to FERC accounts based on the same relationship to the total as the actual costs shown for the Historic Test Year operating and maintenance expenditures, which are reported by both budget classification and FERC account.

Q. How was the operating budget used in this rate filing?

A. The operating budget was used as the basis for forecasting Operating Income for the test year ended September 30, 1995. Please refer to Exhibit MJB 6. The forecasted data shown in Exhibit MJB 6 was reformatted to correspond to FERC account classifications and is shown in Schedule B-2 of Exhibit Future 1 and throughout PP&L's responses to the filing regulations.

Q. Are you aware of the requirement that a comparison of actual to budget data is to be supplied quarterly when a utility utilizes a Future Test Year?

A. Yes. In preparation for complying with this requirement, Exhibit MJB 7 has been provided, showing a breakdown of revenues and expenses for electric operations for the Future Test Year (Exhibit MJB 6) into calendar quarters beginning in October of 1994 and ending September 1995. We will provide quarterly comparisons of actual results to the budget as shown in Exhibit MJB 7 as the actual data becomes available.

Q. Mr. Berish, you also stated you would be testifying to the Company early retirement program. Could you explain this program?

A. Yes. On September 29, 1994, the Company announced a Voluntary Early Retirement Program (VERP). The purpose was to encourage early retirements in an overall effort to reduce the number of employees and, as a result, reduce costs. The VERP contained the following provisions:

- To provide a bridge from an employee's current age to the date he or she would normally begin to receive Social Security: a) a monthly payment of 17.5% of final base pay from the date of retirement to the end of the month in which the employee attains age 62 up to a maximum of $1,000, and b) a monthly payment of 4.5% of final base pay from age 62 to the end of the month in which the employee attains age 65 up to a maximum of $250.

- To offset the normal reduction in pension benefits if employees retire before age 62, 100% of the employees' accrued retirement benefit as of the date of retirement.
- To provide for a transition into retirement, a lump-sum payment at retirement of one week's pay for each year of service.

Q. How many employees were eligible for this program?

A. There were 851 employees eligible for the program. Eligibility was based on being an active employee as of July 31, 1994 and attaining age 55 by December 31, 1994.

Q. How many employees volunteered for early retirement?

A. At the time this filing was prepared, it was assumed that approximately 580 employees would volunteer, in addition to those employee reductions which were already anticipated for the Company's 1995 Budget. The VERP notification deadline was December 15, 1994. If more than 580 unanticipated employees actually volunteer for the early retirement program, an additional adjustment in the filing amount will be made.

Q. What are the savings applicable to the VERP?

A. The Company estimates that there will be a savings due to lower wages of approximately $27.1 million annually and reduced benefit costs of approximately $10.5 million annually. After adjusting for wage and benefit costs applicable to capital accounts, the estimated savings applicable to expense accounts is $19,864,000 in wages and $7,213,000 in benefits, or total expense savings of $27,077,000.

Q. Have these savings been included in the rate filing?

A. Yes. These savings, netted with the cost of the VERP (amortized over a five-year period), are included as an adjustment to the rate filing. This adjustment is shown in Exhibit Future 1, Schedule D-10.

Q. What are the costs of the VERP?

A. The estimated costs of the VERP are $65.8 million and are detailed on Exhibit MJB 8.

Q. What was the $65.8 million estimated cost based on?

A. The cost was also based on an estimated 580 employees taking the VERP. The estimated cost will also be updated when the actual amount is available.

Q. How is the Company proposing to recover the restructuring costs of $65.8 million?

A. The Company is proposing to recover the restructuring costs of $65.8 million, amortized over a five-year period at $13,160,000 per year.

Q. What is the net adjustment the Company is proposing in this rate filing?

A. The Company is proposing a net reduction in the filing of $13,917,000. This reduction consists of $19,864,000 in wage savings, $7,213,000 in benefit savings, partially offset by a five-year amortization of restructuring costs of $13,160,000. The net reduction of $13,917,000 is shown as an adjustment to the filing on Exhibit Future 1, Schedule D-10.

Q. Does this conclude your direct testimony?

A. Yes, it does.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 3

Direct Testimony of Ronald J. Bernini

Docket No. R-00943271

Q. Please state your name and business address.

A. My name is Ronald J. Bernini and my business address is Two North Ninth Street, Allentown, Pennsylvania 18101.

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

A. I am employed by Pennsylvania Power & Light Company (PP&L) in the Financial Department as Manager-Regulatory Accounting.

Q. What is your educational background?

A. I was graduated from St. Joseph's College, Philadelphia, Pennsylvania, in 1964 with a Bachelor of Science Degree in Accounting. In 1966 I received a Master's Degree in Business Administration from Pennsylvania State University. In addition, I have attended specialized courses dealing with depreciation and data processing.

Q. Please describe your professional experience.

A. I was employed by Air Products & Chemicals Incorporated in Allentown, Pennsylvania, as an Internal Auditor from 1966 through 1968. I joined Pennsylvania Power & Light Company in 1969 as an Internal Auditor in the Accounting Division. I was promoted to the position of General Accountant in the General Accounting Division in 1970 and to that of Accounting Analyst in 1973. In 1975 I was promoted to Manager-Regulatory Accounting and in 1988 my title was changed to Manager-Regulatory & Power Contract Accounting, in 1994 my title was changed back to Manager-Regulatory Accounting, the position I now hold.

Q. Mr. Bernini, would you briefly describe the functions you perform in your capacity as Manager-Regulatory Accounting?

A. As Manager-Regulatory Accounting I am responsible for preparing or directing the preparation of financial schedules, exhibits and testimony in connection with rate matters before the Pennsylvania Public Utility Commission (PUC) and the Federal Energy Regulatory Commission (FERC); acting as a witness for accounting and financial matters in formal proceedings before the PUC and the FERC; and keeping abreast of current developments in rate proceedings in

Pennsylvania and other jurisdictions. In the performance of these functions, I accept assignments from and report directly to Mr. Joseph J. McCabe, Controller.

Q. Mr. Bernini, are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring portions of the following: Exhibit Regs. Part I, a multi-page document entitled "General Information"; Exhibit Regs. Part II, a multi-page document entitled "Primary Statements of Rate Base and Operating Income"; Exhibits Regs. Part III, a multi-page document entitled "Rate of Return"; Exhibit Regs. Part IV, a multi-page document entitled "Rate Structure and Cost Allocation"; Exhibit Regs. Part V, a multi-page document entitled "Plant and Depreciation Supporting Data, including Related Depreciation Study Report; Exhibit Regs. Part VI, a multi-page document entitled "Unadjusted Comparative Balance Sheets and Operating Income Statements; Exhibit Regs. Section 53.52, a multi-page document entitled "Information in Response to Section 53.52 of the Commission Regulations"; Exhibit Historic 1, a multi-page document entitled "Summary of Measures of Value & Rate of Return for the Year Ended September 30, 1994"; and Exhibit Future 1, a multi-page document entitled "Summary of Measures of Value & Rate of Return for the Year Ending September 30, 1995."

Q. Please explain how and why the foregoing exhibits were prepared.

A. With regard to Exhibit Regs. I to VI, Section 53.53 of the Commission's regulations requires that all electric utilities seeking a general rate increase in revenues exceeding $1,000,000 must provide specific responses to over 95 questions. The regulation categorizes these questions into six parts as follows:

I. General Information--Electric Utilities

II. Primary Statements of Rate Base and Operating Income

III. Rate of Return

IV. Rate Structure and Cost Allocation

V. Plant and Depreciation Supporting Data, including Related Depreciation Study Report

VI. Unadjusted Comparative Balance Sheets and Operating Income Statements

PP&L's responses to the questions follow the same pattern. Thus, responses to pertinent questions regarding general information are found in Exhibit Regs. I, "General Information." Our responses to questions regarding primary statements of rate base and operating income are found in Exhibit Regs. II, "Primary Statements of Rate Base and Operating Income," etc.

Generally, the Company's responses to the questions reflect unadjusted book data for the historic year and unadjusted projected data for the future test year. The various ratemaking adjustments are reflected in Exhibit Historic 1 and Exhibit Future 1, respectively.

Individuals responsible for the response to a particular question are noted in the upper right-hand corner of the page on which the question is stated. If more than two individuals were involved in the preparation of a response, the notation is "various."

With regard to Exhibit Regs. Section 53.52, the Commission's regulations also provide that in addition to the questions set forth in Section 53.53, utilities seeking a rate increase must also provide responses to the questions set forth in Section 53.52. PP&L's responses to the questions set forth in Section 53.52 are found in this separate exhibit.

Exhibits Historic 1 and Future 1 provide book and projected data as well as various ratemaking adjustments for the years ended September 30, 1994 and September 30, 1995, respectively. As with Exhibit Regs. I to VI, individuals responsible for the preparation of a particular schedule in Historic 1 or Future 1 are noted in the upper right-hand corner.

Q. PP&L is asking for a increase in electric rates of approximately $261.6 million annually. Is this requested increase supported by data for a future or experienced test year?

A. PP&L will rely primarily on data for a future test year ending September 30, 1995. These data are included in Exhibit Future 1. The Commission's regulations require that a public utility which uses a future test year must also submit data for an historic year, consisting of the twelve months preceding the future test year. As a result, PP&L has also submitted data for the 12 months ended September 30, 1994. This is set forth in Exhibit Historic 1.

Q. Mr. Bernini, will you now briefly explain how the schedules included in Exhibits Historic 1 and Future 1 are organized?

A. Yes. These exhibits contain information which is required by the Commission's regulations and each contains a series of schedules. The schedules are grouped into four major categories: Schedule A-1 is a Statement of Reasons for the proposed increase. Those schedules prefixed with the letter "B" are financial statements and data regarding PP&L's securities and capital structure as of September 30, 1994 and September 30, 1995. Those schedules prefixed with the letter "C" relate to measures of value as of September 30, 1994 and September 30, 1995. Those schedules prefixed with the letter "D" pertain to revenues, expenses and operating income for the years ended September 30, 1994 and September 30, 1995 and adjustments thereto.

It should be noted that for both Exhibit Historic 1 and Exhibit Future 1 rounding to the nearest thousands of dollars was employed.

The various schedules in Exhibits Historic 1 and Future 1 are consistently numbered. For example, the claim for Cash Working Capital is Schedule C-4 in both exhibits and the Adjustment to Wages is Schedule D-5 in both exhibits. This should facilitate working with both documents simultaneously.

Q. You have stated that the data in Exhibit Future 1 are for the 12 months ended September 30, 1995. This is obviously a projection of future data. Will you please explain the source of this future data?

A. The basic data in Exhibit Future 1 were derived from PP&L's budget and forecast figures for the 12 months ended September 30, 1995. The procedures followed in preparing the budgets are explained by M. J. Berish, Manager-Financial Planning, for the Operating Budget; and by D. A. Krall, Manager-Generation Development Planning, for the

Construction Budget. In effect, the budget figures take the place of PP&L's actual book figures which serve as the basis of the September 30, 1994 data in Exhibit Historic 1.

Q. Mr. Bernini, would you describe the material presented on Schedules B-1 through B-9 of Exhibits Historic 1 and Future 1?

A. Schedules B-1 show the balance sheets of PP&L at September 30, 1994 and September 30, 1995. These balance sheets are for the entire corporation, which include the assets and liabilities related to the electric utility operations, and investments in nonutility property and associated companies.

Schedules B-2 are statements of electric utility operations showing the operating revenues and expenses and operating income for the year ended September 30, 1994 and test year ending September 30, 1995. Electric operating revenues shown on these schedules are set forth by source in Schedules B-3.

Schedules B-4 show the operation and maintenance expenses of the electric utility operations for the above years by detailed accounts, showing the major categories of expense: power production, transmission, distribution, customer accounts, customer service and informational, sales, and administrative and general. Mr. Berish's testimony explains that certain allocations were used to arrive at projections of operation and maintenance expenses in the categories shown on both Schedules B-2 and B-4 of Exhibit Future 1.

Schedules B-5 present the details of taxes applicable to the electric utility operations. The embedded cost of debt and preferred capital at September 30, 1994 and September 30, 1995 are shown on Schedules B-6 and B-7. PP&L's capital structure from 1989 through September 30, 1995 is shown on Schedules B-8.

All the data shown in Schedules B-1 through B-8 were either taken from the books and records of PP&L for the 12 months ended September 30, 1994 and prior, or were derived from operating and construction budget data for the 12 months ended September 30, 1995.

Schedules B-9 set forth the claimed composite rate of return as of September 30, 1994 and September 30, 1995. In each instance the capitalization ratios at the end of the respective year, as shown on Schedule B-8, were used. The composite cost rate for long-term debt (Schedule B-6) and the composite cost rate for preferred (Schedule B-7) are reflected as embedded costs. As to common equity, the claimed rate of return on common equity is 13%. PP&L's rate of return expert, P. R. Moul, is recommending, and his studies support, a fair rate of return on common equity at this level. The overall rate of return reflected on Schedule C-1 in Exhibit Future 1 will produce a return on common equity of 12.86%.

Q. Please describe the source and method used to establish the book cost of plant shown in the accounts of the Company.

A. The accounts of the Company are kept in accordance with the Uniform System of Accounts prescribed by the PUC and the FERC for Electric Utilities and Licensees. By several orders at Docket No. E.O.C. 34, the last dated December 30, 1947, the PUC determined the original cost of PP&L's plant as of November 30, 1947. Since that time, PP&L has recorded its plant transactions in accordance with the Commission's required system of accounts. The Company's books, therefore, reflect the original cost of its plant at September 30, 1994.

Q. Are these accounts audited?

A. They are audited annually by an independent certified public accounting firm. In addition, the FERC audit staff conducts periodic audits. The latest was an audit through the end of 1991 to ascertain that the Company is keeping its accounts in conformity with the Uniform System of Accounts. In addition, the PUC audit staff has audited the Company's property records.

Q. How do you determine that all property reflected in Account 101, Plant In Service, as shown on Page 1 of Schedules B-1, is actually in service?

A. Our Corporate Accounting Section maintains Continuing Property Records which in effect are a running inventory of all property in service. The dollar total of the Continuing Property Records is the same as the balance shown in Account 101 at September 30, 1994.

The Uniform System of Accounts requires that utilities record all construction and retirements of electric plant by means of work orders or job orders. Further, the work order system must show the nature of each addition to or retirement from electric plant, the total cost thereof, and the plant account or accounts affected.

PP&L has maintained such a work order system since the establishment of its Continuing Property Records system in 1937. Under this system an authorized capital work order is used in connection with all work performed.

When any unit of property is taken out of service permanently, personnel in the field record the removal under a work order and transmit that information to the Plant Accounting Section where the necessary retirement accounting entry is made. Many retirements occur in connection with capital improvement projects, so that the retirement work is part of a construction authorization.

Costs of new construction are reported by work order number and Corporate Accounting accumulates, by work order, all costs associated with a particular job. At the completion of the job Corporate Accounting receives reports from construction forces which show the date the project was placed in service and a complete inventory of property constructed. Based on this information and the cost accumulated under the work order, the property constructed is recorded in appropriate detail on the Company's Continuing Property Records. With this system and its supporting detail, the costs making up any item recorded as Plant In Service can be supported and verified through an audit by the various regulatory agencies which I previously referred to.

Q. With regard to Section C of Exhibits Historic 1 and Future 1, would you describe the material appearing on Schedules C-1, and its derivation?

A. Schedules C-1 develop the Company's measures of value at September 30, 1994 and September 30, 1995 and relate these measures of value to operating income at present rates and proposed rates to determine the return under present and proposed rates. Schedules C-2 through C-6 support the amounts shown on the various lines on Schedules C-1. The supporting schedule reference is shown immediately to the left of each line amount. The source of two deductions from the measures of value, i.e. customer advances for construction and customer deposits, are referenced as Schedule B-1. These items are shown on the Company's balance sheets, which are Schedules B-1.

Q. Would you please describe the relationships of the Measures of Value to Pro Forma Return at Present Rates and Return at Proposed Rates which are shown at the bottom of Schedule C-1, page 1?

A. The derivation of the item "Pro Forma Return at Present Rates - Amount" equalling $366,622,000 and the derivation of the item "Pro Forma Return at Proposed Rates - Amount" equalling $510,275,000 may be found in Exhibit Future 1 Schedule D-1.

The various percentages shown are the relationships of return at present rates and proposed rates to the Measures of Value at original cost.

Q. Would you describe Schedules C-2, "Electric Plant in Service"?

A. Schedule C-2, page 1, of Exhibit Historic 1 presents the electric plant in service at September 30, 1994 by category of plant. The original cost for electric plant in service, shown on page 1, is taken from the records of the Company. These amounts are recorded in Account 101 on the balance sheets at Schedule B-1.

Schedule C-2, page 1, of Exhibit Future 1 presents the electric plant projected to be in service at September 30, 1995 at original cost. The original cost amounts were derived by adding projected additions and deducting projected retirements for the 12 months ended September 30, 1995 to the actual September 30, 1994 book balance for the categories indicated. The projected additions and retirements were obtained from the Construction Budgets (see Exhibits DAK 1 and DAK 2). A recent review of the Construction Budgets indicated certain changes in the in-service dates and other data were in order. These changes are reflected as adjustments to the Construction Budget data (see Exhibit DAK 3). The data reflected in Exhibit Future 1, Schedule C-2, page 1, is discussed in greater detail in Mr. Hoch's direct testimony and related exhibits.

Page 2 of Schedules C-2 for both Exhibits Historic 1 and Future 1 presents the accumulated depreciation applicable to the Electric Plant In Service as shown on page 1 of the respective schedules. The methods used in determining the accumulated depreciation are discussed by Mr. Hoch in his direct testimony and related exhibits.

Q. Would you explain the inclusion of "Pollution Control Projects" on Schedules C-3?

A. These projects are non-revenue producing and do not affect the level of operations at the end of the test year. These projects are generally additions to existing facilities required by environmental regulations, the need for which could not have been foreseen at the time of the initial construction of the facility. Because of these circumstances, this Commission has found, in previous rate orders involving electric utilities, that such expenditures are properly included in the Measures of Value even though the projects may not be in service at the end of the future test year.

The amounts shown in Schedules C-3 in Exhibits Historic 1 and Future 1 represent the actual expenditures on the various projects through September 30, 1994 plus the projected expenditures for the 12 months ended September 30, 1995. The projects in Exhibit Future 1 are the same as those in Exhibit Historic 1 except that projects which are expected to be placed in service during the 12 months ended September 30, 1995 have been deleted and are reflected as part of Electric Plant In Service at September 30, 1995 as shown on Schedule C-2, page 1.

The last page of Schedules C-3 shows the depreciated cost of any facilities which will be removed from service concurrent with placing the pollution control projects in service.

Mr. Krall will discuss the various pollution control projects in more detail in his testimony.

Q. Schedules C-4 show details of the Company's claim for cash working capital. Would you explain these schedules?

A. Schedules C-4 are computations of the Company's average investment in cash working capital. There are five major components in this computation: cash working capital required for operation and maintenance expenses; funds invested in prepayments; adjustment for accrued taxes; adjustment for interest payments; and adjustment for preferred dividend payments.

Q. Would you explain these five components?

A. Page 2 of Schedules C-4 shows the first component, which is cash working capital required for operation and maintenance expenses. The Company bills all of its customers once every month but the due date for payment varies between 15 and 30 days from the billing date. On this basis, there is a considerable span of days between the time electricity is furnished to a customer and the time the customer pays for such electricity. This span averages 35 days for customers with 15-day due dates, 42 days for customers with 20-day due dates, and 39 days for customers with 30-day due dates. Payments received for interchange sales lags the time electricity is delivered by an average of 35 days. Revenue received from power contracts, and UGI have lags of 20 days, and 17 days, respectively. The average lag in receipt of revenues from all these sources is 35.6 days on a dollar-weighted basis.

In most instances the Company must pay its bills for payroll, fuel and other operating expenses prior to the time it is able to collect the amount due for the service giving rise to these expenses. The Company has examined its records to determine, as to the major categories of expense, the average span of days between the time an expense is incurred and the time it must be paid. On page 2, Schedule C-4 of Exhibit Historic 1, the average span of days for major categories of expense is shown. This lag ranges from 11 days to 46 days for various types of costs. The overall average for all expenses is 30.9 days. Thus, the average net lag between the payment of expenses and the receipt of the related revenue is

4.7 days (35.6 days less 30.9 days). To cover its expenses and continue to conduct its business during this time lag the Company must provide a cash investment.

The second major component of cash working capital is made up of funds which are invested in prepayments. This amount is shown on page 3 of Schedules C-4. In conducting its electric business, the Company must pay certain costs prior to the time such items are properly charged to expense for accounting and ratemaking purposes. For example, many insurance premiums must be prepaid but are expensed monthly over the period to which they apply. Costs of this nature are initially charged to Account 165, Prepayments, and are subsequently charged to expense from this account.

The claim for prepaid expenses is based on the 13-month average of the various items included in Account 165. This amount has been claimed as a component of cash working capital for both the historic year and future test year.

The third major component of cash working capital is the adjustment for accrued taxes which is shown in detail on page 4 of Schedules C-4. In the case of Federal income tax, estimated payments must be made on April, June, September and December 15 of the year to which the tax is applicable. Since revenues are collected from customers monthly, there are funds temporarily available for payment of other costs. Our computations indicate that funds available from this source average 6.72 percent of the federal income tax due.

Presently the Pennsylvania income tax and Pennsylvania Capital Stock Tax have an effective pattern of required estimated payments as follows:

- 22.5 percent on March 15
- 22.5 percent on June 15
- 22.5 percent on September 15
- 22.5 percent on December 15
- 10 percent on April 15 of the following year

Our computations indicate that the funds available from these taxes average 11.72 percent of the tax due.

The Pennsylvania gross receipts tax must be paid on an estimated basis by March 15 with final payment due on March 15 of the following year. The Company's estimated payment on March 15 generally is equal to 90 percent of the final tax due. Revenue is collected from customers monthly and funds must be provided by investors to pay these taxes prior to collection of revenues from customers. Our computations indicate that the funds which must be provided for this purpose average 22.87 percent of the tax due. This adjustment is based on the total Pennsylvania gross receipts tax which must be paid at the 44 mill rate actually in effect.

The Pennsylvania Public Utility Realty Tax must be paid on an estimated basis by April 15 with final payment due on April 15, of the following year. The Company's estimated payment on April 15 generally is equal to 90 percent of the final tax due. Our computations indicate that funds which must be provided for this purpose average 14.53 percent of the tax due.

The net effect of these various accrued tax adjustments is a decrease in the Company's cash working capital requirement as shown on page 4 of Schedule C-4 in Exhibit Future 1.

The fourth and fifth component of cash working capital are offsetting adjustments for the funds applicable to debt interest payments and preferred stock dividend payments which are shown in detail on pages 5 and 6 of Schedules C-4. The Company "theoretically" has unrestricted use of these funds from the time of the monthly collection from customers until the payment of interest and dividends on a semiannual or quarterly basis. The Company does not agree with the appropriateness of such a reduction to Measures of Value. However, this adjustment has been made in order to facilitate the adjudication of this filing and in compliance with the Commission's current policy.

Q. Mr. Bernini, would you explain Schedules C-5, "Fuel Stock and Materials and Operating Supplies"?

A. Schedules C-5 reflect the amount required to be invested in coal and oil used as fuel at PP&L's various generating stations, as well as the materials and supplies stored principally at power plants and service area storerooms to supply line crews. As to the fossil-fired generating stations, pages 2 and 3 show the normal fuel quantities in tons, barrels or gallons applicable to the various generating stations for the test years ended September 30, 1994 and September 30, 1995. For purposes of the historic year, the inventory prices at September 30, 1994 are applied to the normal inventory quantities to develop average inventory values for coal and oil. For purposes of the future test year, the projected inventory prices at September 30, 1995 are applied to the normal inventory quantities to develop average inventory values for coal and oil. These values are increased by the fuel stock expense applicable to the various fuels, which is principally the cost of purchasing and other procurement expense of the fuel in inventory.

Pages 5-6 of Schedule C-5 in Exhibit Historic 1 shows the dollars invested by PP&L in materials and operating supplies for the thirteen months ended September 30, 1994 plus the stores expense applicable to this inventory balance.

Monthly detail of materials and operating supplies on a projected basis for the 12 months ended September 30, 1995 are shown on pages 5-6 of Schedule C-5 in Exhibit Future 1.

Q. Please explain Schedules C-6, "Accumulated Deferred Taxes on Income." Are the totals shown on these schedules used to reduce the Measures of Value?

A. Yes, the totals shown on these schedules are reflected as a reduction of the Measures of Value on Schedules C-1. These totals are balances of various deferred income taxes which have been established by charges or credits to operating expense over the years and, in concept at least, have been reflected in the level of revenues paid by customers. The charge or credit for deferred taxes, at the time recorded, is a noncash item. Accordingly, these transactions effectually produce cash, with no related carrying costs, which can be used for various corporate purposes. These savings in carrying costs are passed back to customers through the mechanism of reducing the Measures of Value by the deferred tax balances.

Schedules C-6 of Exhibits Historic 1 and Future 1 reflect the balances in deferred taxes at the end of the respective years. I might point out that Schedules C-6 reflect the tax deferrals related to the Accelerated Cost Recovery System (ACRS). This legislation provides for mandatory normalization of tax benefits on post-1980 property. Only federal income tax normalization is claimed in this filing.

I have now explained all the items shown on Schedules C-1 comprising Measures of Value except two items, referenced B-1, which are shown on the Company's balance sheet. These items are reductions from rate base. The first item is customers' advances for construction which represents amounts held in Account 252 at September 30, 1994 pending completion of construction or conclusion of the period during which some portions may be refundable under tariff provisions and service contracts with customers. These are relatively recent advances and the balance is comprised of many small amounts. The second item is customer deposits. These deposits are deducted in compliance with the Commission's Order at Docket No. R-80031114, entered January 30, 1981. In view of this adjustment, the 11 percent interest which PP&L must pay on these customer deposits has been included in operating expenses.

Q. Why aren't Accumulated Deferred Investment Tax Credits (as shown in Account 255) reflected in the computation of Measures of Value?

A. Under provisions of the Revenue Act of 1971 public utilities were afforded the option of treating the investment tax credit in rate proceedings by reducing operating taxes over the life of the property and not deducting the accumulated amount of the credit from the Measures of Value.

On March 8, 1972, the Company made this election as provided under the Internal Revenue Code, Section 46(e), Paragraph (2), and in compliance therewith has not reduced the Measures of Value for the purpose of these proceedings. Such credits are, however, being amortized as a credit to operating expense over the life of the related property.

Q. Does this conclude your testimony on the "B" and "C" Schedules?

A. Yes it does.

Q. Would you explain the "D" Schedules?

A. The "D" Schedules are the financial information supporting the operating income applicable to this filing. This information is reflected in Section D of Exhibits Historic 1 and Future 1. In general, the schedules prefixed with a "D" in Exhibits Historic 1 and Future 1 were prepared by me or under my supervision. Schedules D-3, D-4, D-10, D-15 and D-17 will also be addressed in the testimony of Mr. Kasper, Mr. Sipics, Mr. Berish, Mr. Bujnowski and Mr. Hoch, respectively.

Q. Would you describe the material appearing in Schedules D-1 relating to operating income?

A. Schedules D-1 begin with actual operating revenues and expenses for the historic test year, and projected operating revenues and expenses for the future test year, and set forth the effects of adjustments made thereto to show, on a pro forma basis, operating income both at present and at proposed rate levels. These two levels of operating income are related to the respective measures of value on Schedules C-1 to demonstrate the rate of return at present rate levels and at proposed rate levels.

Specifically, column 1 of Schedules D-1 is a statement of operating income for each test year. The figures in column 1 are basically the same as shown on Schedules B-2.

Column 2 of Schedule D-1 is a summary of adjustments that apply to certain revenue and expense items. These adjustments are shown in greater detail on Schedule D-2. Column 3 is an adjusted statement of operating income on a total Company basis. Column 4 reflects the adjusted statement of operating income on a PUC jurisdictional basis. The source of the data for the years ended September 30, 1994 and September 30, 1995 in this column were Exhibit JMK 2 and Exhibit JMK 3. Column 5 shows the revenue increase which would result under proposed rates applicable to PUC jurisdictional customers and the additional taxes that would be incurred as a result of this additional revenue. Column 6 is a statement of PUC operating income as adjusted for the proposed rate increase.

Q. You stated that Schedule D-1, column 2, and all of Schedule D-2 of Exhibits Historic 1 and Future 1, reflect adjustments to operating revenues and expense for both test years. Would you explain the basic reasons for these adjustments?

A. There were three basic reasons for making the various adjustments:

First - Revenues and expenses were brought up to the level which will be experienced at the end of or shortly following the end of the test years. For example, wages were adjusted to reflect wage rates which will be paid at the end of the respective test years.

Second - Certain abnormal or nonrecurring expenses were eliminated or normalized.

Third - Revenue and expenses applicable to the Energy Cost Rate and Pennsylvania State Tax Adjustment Surcharge were rolled into base rates along with the portion of the Special Base Rate Credit Adjustment revenues associated with the Atlantic City Electric Agreement.

Q. I note on Schedule D-1, column 5 of Exhibit Future 1 that the requested increase in base rates results in a much lower increase in operating income. Will you comment on this?

A. The difference between these two amounts are various taxes incurred relative to the increased revenues. The details of the various taxes incurred in connection with the increase are shown on Schedule D-19, page 5. It must be recognized that many of the costs described in support of the requested rate increase already have been incurred and are reflected on the records for the 12 months ended September 30, 1994. Higher costs cause the Company's actual return on investment to decline substantially below the levels allowed by this Commission. As return (earnings) decline, income taxes also decline. The adjustments reflected in column 2, Schedule D-1 of Exhibit Future 1 are merely increases in costs not already reflected in the budget for the 12 months ended September 30, 1995, and will result in a future decline in earnings. In presenting the data for purposes of this filing, all higher costs are reflected in Exhibit Future 1, Schedule D-1, column 3 and all related income tax savings are also reflected there. Therefore, when the revenue increase is projected it appears to be fully subject to income tax since all tax savings resulting from higher costs are already reflected in the figures.

Q. Would you describe and explain Schedules D-2, "Adjustments to Income"?

A. The purpose of both of these schedules is to summarize the various adjustments to income. These schedules support the amounts shown in column 2, Schedule D-1 of Exhibits Historic 1 and Future 1. The adjustments are shown in four major groupings on Schedule D-2: adjustments to operating revenue; adjustments to operation and maintenance expense; adjustments to depreciation expense; and adjustments to provision for taxes. Schedules D-3 through D-21 support the amounts shown on Schedules D-2. The supporting schedule reference is shown immediately to the left of each line caption.

Q. Please explain Schedules D-3 and D-4 for both test years.

A. Mr. Kasper's testimony deals with Schedules D-3 and explains annualization of and other adjustments to operating revenue. He also explains the revenue effect of the proposed rate increase.

Schedules D-4 reflect adjustments to current energy costs for customer load growth as well as the normalization of retired miners' health care cost in accordance with the ECR Settlement Agreement at Docket No. M-00900238 et al.

The adjustments to budgeted data shown on D-4 were provided by the Company's Power System Support Department.

Q. Please explain Schedules D-5, "Adjustment to Wage Expense."

A. This adjustment normalizes wages. The total wages paid to all employees during the last three months of the historic year and to be paid during the last three months of the future test year were examined to determine the average wage per employee. The use of the three month average was necessary in order to reflect the level of wages which were in effect at September 30, 1994, and September 30, 1995, respectively. This average monthly wage was then multiplied by the total number of personnel employed at September 30, 1994, and those budgeted to be employed at September 30, 1995, to arrive at the total monthly payroll. By multiplying the total monthly payroll by twelve months, the total annual wages were computed. From this amount was deducted the actual or budgeted wages for the year. The difference was then multiplied by the portion charged to operating expense to arrive at the wage adjustment.

Q. Would you explain Schedules D-6?

A. Effective January 1, 1993, Statement of Financial Accounting Standards No. 106 ("SFAS 106") required all entities subject to generally accepted accounting principles, including PP&L, to cease using a cash basis method of accounting for post-retirement benefits other than pensions (Other Post-Employment Benefits or "OPEBs") and required them to begin using an accrual basis method of accounting for these benefits.

Compliance with SFAS 106 has resulted in a substantial increase in the level of expense for OPEBs reflected in PP&L's financial statements.

On December 4, 1992, the Company filed a petition with the PUC requesting permission to defer and recover in future rates prudently incurred incremental costs of OPEBs that the Company was required to recognize beginning January 1, 1993. By Order entered May 6, 1993, the PUC approved PP&L's petition.

The Commission's approval granted PP&L permission to defer and record, as a regulatory asset, the incremental amount by which the accrued cost for OPEBs under SFAS 106 (including amortization of the Transition Obligation) exceeds the amount actually paid for such benefits during the deferral period. The deferral period was from the date of SFAS 106 adoption (January 1, 1993) until the effective date of base rates which reflect recognition of SFAS 106 compliance costs, but, in any event, no later than January 1, 1998. The Order further provided that, in a future rate case, the Company would be permitted to include in base rates an amortization of the recorded regulatory asset over a period not to exceed twenty years from the date of adoption of SFAS 106.

On May 26, 1994, the Commonwealth Court reversed the PUC order which granted the Company's SFAS 106 petition.

Both PP&L and the PUC have filed Petitions for Allowance of Appeal asking the Pennsylvania Supreme Court to review the Commonwealth Court's decision.

Schedules D-6 set forth the adjustment made to reflect the full annual effect of accounting for post-retirement benefits other than pensions on an accrual basis as required by SFAS 106. In addition, Schedules D-6 reflect the amortization of incremental SFAS 106 post-retirement benefits incurred from January 1, 1993 through September 30, 1995 as those additional costs have not been recovered from customers.

Q. Mr. Bernini, will you explain Schedules D-7 for both test years?

A. Schedules D-7, "Adjustments to Rate Case Expense," reflect the required adjustment of this item of expense. I understand that the PUC follows a procedure whereby claimed rate case expense is normalized. Schedule D-7 reflects a 2-year normalization of rate case expense applicable to this proceeding. This normalized amount is compared to the actual regulatory commission expense for the 12 months ended September 30, 1994, and the budgeted regulatory commission expense for the 12 months ended September 30, 1995, to arrive at the adjustment to operating expense for the historic and future test years.

Q. Will you please explain Schedules D-8, "Adjustment for Land Management Projects/Recreational Facilities Expense"?

A. In its final order at Docket No. R-822169, entered August 22, 1983, the Commission determined that operation and maintenance expenses incurred for certain land management projects/recreational facilities which are not owned or operated pursuant to a specific Federal or State licensing requirement should not be recovered from ratepayers. The adjustment on Schedules D-8 provides for the elimination of the test year operating expense for such facilities.

Q. Will you please explain Schedules D-9?

A. Yes. Schedules D-9 calculate interest expense applicable to customer deposits at a rate of 11%. This adjustment is consistent with the Commission's policy of allowing appropriate interest expense when customer deposits are treated as a reduction to the measures of value. In this filing, PP&L has treated customer deposits as a reduction to the measures of value.

Q. Would you please explain Schedules D-10?

A. On September 29, 1994 the Company announced a voluntary early retirement program ("VERP") to all management employees who would be 55 or older by December 31, 1994.

Agreement on a VERP applicable to eligible bargaining unit employees was also reached with the union.

Schedules D-10 reflects an adjustment to expenses to amortize the estimated cost of the VERP over five years and reduce wages and benefits for the anticipated annual savings of the program. Mr. Berish will discuss this adjustment in his testimony.

Q. Mr. Bernini, will you provide additional detail related to the development of the annual decommissioning expense shown on Schedules D-11?

A. In his direct testimony and accompanying exhibit, Mr. Thomas S. LaGuardia, P.E., President of TLG Services, Inc. discussed a site-specific decommissioning cost study of the two generating units at the Company's nuclear fueled Susquehanna Steam Electric Station (SSES). The estimated cost of immediate dismantlement of both the radiological and non-radiological portions of the facility is $804.3 million in 1993 dollars. Allegheny Electric Cooperative, Inc. owns 10 percent of SSES; therefore, only 90 percent of the total cost or $724 million is applicable to PP&L.

Based on this estimate, an annual decommissioning expense for each unit is determined using an annuity method as set forth on Schedule D-11.

Q. Will you please explain the annuity method in more detail?

A. Unit 1 has an operating license which expires in the year 2022 while Unit 2 has an operating license which expires in the year 2024. PP&L's share of the decommissioning cost of $315.5 million for Unit 1 and $408.4 million for Unit 2 in 1993 dollars is escalated at an annual rate of 4 percent to determine the cost of decommissioning in the years 2022 and 2024, respectively.

The value of the decommissioning trust for each unit at September 30, 1995 was estimated. The projected value of the trust in the year 2022 for Unit 1 and 2024 for Unit 2 was determined assuming the trust realizes a 5.5 percent annual after-tax rate of return. The value of the trust is deducted from the cost of decommissioning to determine the net amount of additional decommissioning funds which must be provided for through the annuity method. This resulted in an annual cost for decommissioning of $12.6 million for Unit 1 and $17.4 million for Unit 2.

Q. Is the decommissioning expense deductible for tax purposes?

A. Yes, the funding of the decommissioning expense is deductible for tax purposes to the extent such funding is made in accordance with Section 468A of the Internal Revenue Code and as determined by the Internal Revenue Service in "schedules of ruling amounts" approved and issued by it.

Q. Has the Company received a "schedules of ruling amounts" applicable to PUC jurisdictional customers under Code Section 468A?

A. Yes. The Company received a "schedule of ruling amounts" from the IRS applicable to Unit 1 in July, 1987. A "schedule of ruling amounts" applicable to Unit 2 was received in August, 1987.

Q. What was the basis of the "schedules of ruling amounts?"

A. The "schedules of ruling amounts" were based on a qualifying percentage of 97.5 percent of the amount of decommissioning expense currently allowed in rates for Unit 1 and 100 percent of the amount of decommissioning expense currently allowed in rates for Unit 2. The amounts allowed in rates were based on a decision by the PUC in a 1985 rate case (Docket No. R-842651). The qualifying percentage is required by the IRS regulations and reflects the fact that Unit 1 began commercial operation prior to 1984 which is the first taxable year a deduction for decommissioning is allowed by the IRS.

Q. Will the Company request new "schedules of ruling amounts" from the IRS as a result of a decision in this case?

A. Yes, the Company would expect to file with the IRS for new "schedules of ruling amounts" based on the decision in this case. However, the Company is unable to predict whether the IRS would approve the "schedules of ruling amounts" requested by the Company. The Company, would expect, that the IRS would continue to apply a 97.5 percent qualifying percentage to the amount allowed in rates for Unit 1.

Q. How will the Company account for the decommissioning expense collected from customers?

A. The Company will charge operating expense and credit the reserve account for the decommissioning expense reflected in the rates charged customers. The Company will deposit into the trust an amount equal to the "schedules of ruling amounts" plus the after-tax portion of the amount included in rates in excess of the "schedules of ruling amounts."

Q. Please explain Schedules D-12, "Adjustment to Decommission Fossil Units."

A. Schedules D-12 present a claim for decommissioning the Company's fossil fueled generating stations based on an annuity method. The annuities are based on site-specific decommissioning cost estimates in 1994 dollars completed by TLG Services. These decommissioning cost estimates are also supported by the direct testimony and accompanying exhibit of Mr. LaGuardia.

Q. Is the annuity method employed for the fossil units similar to that used for nuclear decommissioning?

A. The annuity method used for the fossil units is basically the same as that used for the SSES. The cost estimate in current dollars for each unit was escalated at an annual rate of 4% to the scheduled retirement date. This determines the cost of decommissioning in the year retired which is the amount to be provided for through the annuity method. An annuity amount for each unit was determined assuming the fund would earn at an after tax rate of 5.5 percent. This resulted in the annual cost of decommissioning set forth on Schedule D-12.

Q. Does the Company plan to establish a fund for the decommissioning of the fossil units?

A. The Company will establish a trust fund to be used for the decommissioning of the fossil units. Recognizing that the IRS will not permit a tax deduction for this expense prior to the time the actual decommissioning expense is incurred, only the after-tax amount of the decommissioning expense allowed in rates will be deposited into the trust fund.

Q. What type of securities should the Company be allowed to invest these funds?

A. The Company should be allowed to invest these funds in the same types of securities in which the nuclear decommissioning funds are invested.

Q. Will you please explain Schedules D-13, "Adjustment for Amortization of Management Audit Cost"?

A. The adjustment on Schedules D-13 provides for the amortization over a 5-year period of the cost of a comprehensive management audit required by the PUC. The audit was performed by Shumaker & Company.

Q. Please explain Schedules D-14.

A. This adjustment amortizes the "early window" deferrals applicable to Susquehanna Units 1 and 2 over a period of ten years. This is consistent with the PUC Order entered May 16, 1990 in the Philadelphia Electric Company rate case at Docket No. R-891364. The deferral of these costs for Units 1 and 2 was authorized by the PUC in its Orders at Docket Nos. P-820367 entered July 29, 1982 and P-830461 entered November 9, 1983 respectively.

Q. Please explain the adjustment to include amounts related to PP&L's new customer and community needs programs appearing in Schedules D-15.

A. As explained by Mr. Bujnowski, PP&L is planning to initiate eight new programs designed to support customer and community needs. These programs build on and supplement PP&L's existing customer and community needs programs. Schedule D-15 sets forth the Company's claim of $3,500,000.

Q. Schedules D-16 reflect an adjustment for environmental remediation. Would you indicate why this adjustment is made.

A. The test year included only nine months of environmental loss contingencies expenses. This adjustment annualizes the amount of the expense to a twelve month level.

Q. Please explain Schedules D-17.

A. Schedules D-17, relating to depreciation, will be explained by Mr. Hoch.

Q. Please explain the "Adjustment to Taxes Other Than Income Taxes" shown on Schedules D-18 for both test years.

A. It should first be noted that increases in Pennsylvania taxes covered by the tax surcharge are eliminated from our claim in Schedules D-18.

In order to arrive at a current level for Pennsylvania Capital Stock Tax, the valuation method used by the Pennsylvania Department of Revenue has been utilized. This results in an estimated valuation at September 30, 1994 and September 30, 1995. The 12.75 mill tax rate is applied to these valuations to arrive at the total capital stock tax. This portion of the computation is set forth on Schedules D-18, page 2. From this amount is deducted the capital stock tax expense per books for the 12 months ended September 30, 1994, and the expense per budget for the 12 months ended September 30, 1995. Thus, this adjustment reflects both the current taxable valuation and current rates.

Q. Please explain the Pennsylvania Gross Receipts Tax shown on Schedules D-18.

A. The adjustment to Pennsylvania Gross Receipts Tax is shown on Schedules D-18, page 3. This adjustment reflects the gross receipts tax changes which will result from base rate revenues generated by the annualization of sales and the roll-in of ECR revenue.

Q. Now please explain the adjustment for Pennsylvania Public Utility Realty Tax.

A. The Pennsylvania Public Utility Realty Tax is developed based on plant projected to be in-service at September 30, 1995. From this amount is deducted the expense per books for the 12 months ended September 30, 1994, and the expense per budget for the 12 months ended September 30, 1995.

Q. Mr. Bernini, please explain the adjustment of federal and state income taxes, shown on Schedules D-19 for both test years.

A. Schedules D-19 show, in column 1, the tax computation as booked in the 12 months ended September 30, 1994, and as budgeted for the 12 months ended September 30, 1995. Column 2 shows various adjustments required for a proper computation of taxable income on a pro forma basis at present rates. Column 3 shows the pro forma income tax computation at present rates.

Taxable income and the tax computations are adjusted in Column 2 for the following reasons:

- To reflect the effect on taxable income of adjustments to expense set forth on Schedules D-2 and to reflect other changes in taxable income.

- To eliminate prior year tax adjustments and provisions for possible tax deficiencies recorded on the books for the 12 months ended September 30, 1994, or reflected in the budget for the 12 months ended September 30, 1995.

Q. Are there several tax adjustments upon which you wish to elaborate?

A. Yes. They are the following:

Tax Depreciation

In general, depreciation for tax purposes must be computed using the tax basis of the property (which generally is lower than book basis) and using various depreciation methods and rates which differ from those used in computing book depreciation.

In computing tax depreciation for purposes of this filing, we have paralleled the methods used in filing the Company's federal and Pennsylvania income tax returns. That is, for property acquired prior to 1981 and where permitted we have used the declining balance method of depreciation with the 20% shorter lives permitted by the Class Life Depreciation System (commonly referred to as ADR). The Revenue Act of 1971 introduced ADR which permitted shortening or lengthening depreciable lives as much as 20% for tax purposes. For post-1980 property, including SSES Units 1 and 2, the tax depreciation is based on the Accelerated Cost Recovery System (ACRS) as provided for in the Economic Recovery Tax Act of 1981.

Annualized Interest

This adjustment is the result of normalizing the interest deduction based on the test year measures of value as shown on Schedules D-19, page 3. Because ratepayers pay a return only on these measures of value, it is only the interest associated with these measures of value that applies to the electric operations for ratemaking purposes.

Q. Please summarize the effects of these tax adjustments.

A. Recognition of all tax adjustments reflected on Schedules D-19 results in a net decrease in taxable income for the historic and future test years. Taxable income is the basis for computing both federal and Pennsylvania income taxes.

The actual Pennsylvania Corporate Net Income Tax rate is 11.99% effective January 1, 1994 and 10.99% effective January 1, 1995.

The federal income tax is computed at the current 35% tax rate. For federal income tax purposes, the amount of Pennsylvania income tax is an allowable deduction.

Details of the computations of all taxes incurred as a result of the proposed revenue increase are shown on Schedules D-19, page 5.

Q. Please explain Schedules D-20, "Adjustments to Deferred Income Taxes," for both test years.

A. Normally, deferred taxes arise in connection with expenses which, for various reasons, are recorded on the books as an expense in a different year than the same item is allowed as an income tax deduction. This is referred to as a timing difference. Generally accepted accounting principles prescribed by the Financial Accounting Standards Board (FASB) require that the tax savings related to an expense be recorded on the books at the same time as the expense is recorded. For example, if the expense is booked in a year after its deductibility for tax purposes, a deferred tax charge is recorded on the income statement and a liability for such tax is recorded on the balance sheet in the year the tax deduction occurs. The same basic principle applies to revenue items as well as expense items.

Schedules D-20 show the normalization of the net deferrals recorded on the books for the 12 months ended September 30, 1994 and as budgeted for the 12 months ending September 30, 1995.

Please note that for the year ended September 30, 1994, the specific items covered by deferred taxes all arise in connection with timing differences which I previously explained. Several of the items are expected to result in a continuing charge or credit to expense, the same as recorded on the books or as budgeted, and these do not require adjustments for purposes of this rate filing. The following are unadjusted in both the historic and future years:

- o Accelerated amortization of pollution control facilities.
- o Portion of tax depreciation arising from shortening lives by 20% under the class life depreciation system.

- o Cost of removing retired depreciable property.
- o Martins Creek Unit 4 test power.
- o SSES test power.

The major adjustment relates to the ACRS system of tax depreciation as set forth on Schedule D-20, page 2.

In connection with Schedules D-20, I mentioned that PP&L used the Accelerated Cost Recovery System (ACRS) in computing tax depreciation on post-1980 property additions. Schedule D-20 reflects an adjustment for the mandatory deferral of the federal tax effects of ACRS based on the tax plant balances at the year ended September 30, 1994 and September 30, 1995.

Q. Was the Pennsylvania state income tax effect of ACRS normalized and claimed in these proceedings?

A. In accordance with this Commission's policy, it was not.

Q. Please explain Schedules D-21?

A. Schedules D-21 adjust the amortization of the investment tax credit to reflect a full year's amortization based on the unamortized investment tax credit remaining at September 30, 1994 and September 30, 1995, respectively.

Q. Does this conclude your direct testimony?

A. Yes, it does.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 4

Direct Testimony of Donald S. Hoch

Docket No. R-00943271

Q. Please state your full name and business address.

A. Donald S. Hoch, Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsylvania Power & Light Company (PP&L or Company) as Supervisor - Plant Accounting.

Q. What are your duties as Supervisor - Plant Accounting?

A. I am responsible for managing the maintenance of Company records of construction, plant in service and depreciation in accordance with Federal and State regulatory bodies and Company requirements. I am also responsible for providing timely information concerning the physical property of the Company to various Company departments for use in studies and reports for management and regulatory bodies.

Finally, I am responsible for the preparation of service life studies using the retirement records of the Company in order to ascertain the average service life and dispersion characteristics of utility property.

Q. What is your educational background?

A. I am a graduate of Grove City College with a Bachelor of Science degree in mathematics and of Lehigh University with a Master of Science degree in Industrial Engineering with an emphasis on Information Systems. I have also participated in depreciation seminars for five years at Michigan Technological University and at Calvin College in Michigan, and in numerous IBM courses and seminars concerning computer programming, system analysis and design, and computer-related topics.

Q. How long have you been employed by PP&L and in what capacities?

A. I was employed by PP&L in 1969. From 1969 through 1971 I worked in the Operations Research Section of the Company where my responsibilities were to design systems and computer programs for engineering, scientific and financial applications. This work primarily consisted of the development of a critical path method system which was used to schedule construction projects and allocate resources.

In 1971 I was assigned to assist in the redesigning of the Company's Plant Accounting System, the associated data base of plant records and all the programs and related systems. Included were subsystems for actuarial and simulated plant record (SPR) life analysis studies, depreciation studies, the maintenance of Company trend and Iowa curve files, plant valuations, the depreciation reserve and a variety of other reports and records. This work included the preparation of all trending and depreciation exhibits and studies which were filed in support of rate filings submitted to the Pennsylvania Public Utility Commission in 1969 (Docket No. C-18908), 1971 (Docket No. C-19244), 1973 (R.I.D. No. 84), 1975 (R.I.D. No. 221), 1980 (Docket No. R-80031114), 1981 (Docket No. R-811636), 1982 (Docket No. R-822169), and 1984 (Docket No. R-842651).

Subsequent to the redesign assignment, I developed and maintained several deterministic/probabilistic modeling systems, including a

Company financial model, a general modeling system to simulate user-defined models and a model of future plant based on budget estimates. In September 1981, I assumed full responsibilities as Manager-Depreciation. In that position I was responsible for all aspects of book depreciation, including preparation of depreciation studies using the retirement records of the Company to ascertain the average life and dispersion characteristics of electric property. These studies are currently used as a basis for calculating annual depreciation for accounting purposes, as well as both annual and accrued depreciation for rate studies.

In November 1994, I assumed the position of Supervisor-Plant Accounting.

Q. Have you participated in professional programs or educational projects other than those you previously mentioned?

A. I am a member of the Property Accounting & Valuation Committee of the Edison Electric Institute. I have also received certification in data processing (C.D.P.) from the Institute for the Certification of Computer Professionals.

Q. What is the purpose of your testimony?

A. I will explain the Company's claims for the original cost of utility plant in service, accrued depreciation and annual depreciation expense. In this regard, I will sponsor Exhibit DSH 1, which is entitled "Service Life Study," and Exhibit DSH 2, which is entitled "Future Plant Estimation Process."

Q. Mr. Hoch, were Exhibits DSH 1 and DSH 2 prepared by you or under your supervision?

A. They were prepared under my direct supervision. I will be specifically referring to each of them in my testimony.

Q. Please explain the major components of the Company's claims for the original cost of utility plant-in-service, accrued depreciation and annual depreciation expense.

A. The following is an enumeration of the key plant or depreciation items in this rate filing:

1. ORIGINAL COST MEASURE OF VALUE

PP&L is basing its rate base claim on the original cost measure of value, as required by Section 1311 of the Public Utilities Code.

2. TRANSMISSION, DISTRIBUTION AND GENERAL PLANT AVERAGE SERVICE LIVES, RETIREMENT DISPERSIONS, AND ANNUAL DEPRECIATION RATES

For all plant accounts in these functions, the average service lives and retirement dispersions being used are based on a service life study completed in 1993. The service life study is presented in Sections 1 through 5 of Exhibit DSH 1 in this rate filing. The actuarial techniques used in the current study are the same as those employed in a prior service life study, completed in 1981, which was accepted by the Commission in its final order at Docket No. R-842651. The calculation of the annual accruals reflects the application of the service life parameters from the service life study and the straight-line remaining life method of depreciation. In its order at Docket No. P-880332, the Commission ordered the Company to change from whole-life to the remaining life technique, effective January 1, 1989.

3. STEAM PRODUCTION, NUCLEAR PRODUCTION, HYDRO PRODUCTION AND OTHER PRODUCTION INTERIM SURVIVOR CURVES

The interim survivor curves used as a parameter of the life-spanning depreciation system for power production facilities in Steam Production, Nuclear Production, Hydro Production and Other Production are based on an interim retirement study completed in 1993. In this filing, for the first time, Hydro Production is being depreciated using the life-spanning depreciation system rather than the average service life system. The results of the interim retirement study are presented in Section 3 of Exhibit DSH 1 in this rate filing. A prior interim survivor study completed in 1982, which used the same analytic techniques as the current study, was accepted by the Commission in its final order at Docket No. R-842651.

4. POWER PRODUCTION UNIT DEACTIVATION DATES

The deactivation dates and resulting life spans used for life-spanning depreciation calculations have been reduced for Martins Creek Units 1 and 2, Sunbury Steam Electric Station ("SES") and Holtwood SES, and extended for Conemaugh SES and Keystone SES. The deactivation dates of all the combustion turbine and diesel units at the above-mentioned plants were revised to coincide with the estimated deactivation dates of the respective plants where they are located. This material is covered in Exhibit DSH 1 and Exhibit DAK 4, sponsored by Mr. Krall.

5. BOOK DEPRECIATION RESERVE

As in the prior rate filings, PP&L is claiming its book reserve as the proper depreciation reserve to be used in determining the rate base for all plant. The book reserve was adopted by the Commission for ratemaking purposes in its final order at Docket No. R-842651. The details of this reserve by account and comparisons to the calculated reserve are contained in response to Commission Regulation V-B-1.

6. DEVELOPMENT AND USE OF FUTURE TEST YEAR PLANT AND DEPRECIATION DATA

The original cost of future test year plant in service was developed by adding to the plant balances at September 30, 1994, the original cost of plant claimed as future test year additions in this case less retirements that will occur during the future test year. The additions and retirements are shown in Exhibit DSH 2. The book reserve was brought forward from September 30, 1994 to September 30, 1995 using the Company's budgeted accruals for that period, as reduced by the original cost of property retired and net negative salvage and as increased by an annual amount of the amortization for net negative salvage. These data are shown in the response to Commission regulation V-A-3.

7. SUSQUEHANNA MODIFIED SINKING FUND DEPRECIATION

Property installed at Susquehanna prior to January 1, 1989 is depreciated using a system of depreciation known as modified sinking fund (MSF). This method was approved by the Commission in its final order at Docket No. R-842651 and subsequently modified by the Commission at Docket No. P-880332 to permit the Company to comply with the requirements of Statement of Financial Accounting Standards No. 92 ("SFAS 92"). As more fully explained hereafter, the Company is proposing a revision that will result in a levelized amount of annual depreciation, through 1998, in lieu of remaining on MSF, which results in increasing annual accruals over that same period.

8. GENERAL PLANT AMORTIZATION

Currently, the Company depreciates General Plant accounts 391.2, 391.4, 391.6, 393.0, 394.0, 394.4, 394.6, 394.8, 395.0 and 398.0 using the straight-line remaining life method of depreciation and the broad group procedure. In this filing, the Company is proposing to switch to amortization accounting for these classes of assets. This proposal will be discussed in more detail later in my testimony.

Q. Please explain the contents of Exhibit DSH 1.

A. Section 1 of Exhibit DSH 1 contains a detailed description of a service life study that was conducted to arrive at reasonable judgments of average service lives and retirement dispersions for all accounts in the Transmission and Distribution functions and selected accounts in the General Plant function (390.2, 390.4, 391.8, 392.4 and 397.0). This study was completed in 1993 using retirement and survivor data through December 31, 1992.

Q. How often is such a study conducted?

A. A complete study of all accounts is undertaken every three or four years. To do a complete study on a more frequent basis would simply not allow time for significant changes to demonstrate themselves and would be extremely time-consuming. To wait longer than, approximately five years would present the possibility of missing some significant changes in lives and retirement dispersion patterns.

Q. When was the last study completed that this Commission reviewed and approved?

A. The last study that was presented to the Commission was completed in 1981 using retirement and survivor data through December 31, 1980. This study was approved by the Commission at Docket No. R-842651. However, subsequent to that filing, several other service life studies were completed but never presented in a rate filing because there had been no opportunity to do so.

Q. Have you included any analysis of property in the Steam Production, Hydro Production and Other Production functions?

A. Yes. Property in these functions is depreciated using the so-called life-spanning system of depreciation. Since the Commission order issued on August 26, 1976 at R.I.D. No. 221, PP&L has used this system of depreciation to calculate book depreciation for Steam and Other Production. This system is being proposed for Hydro Production in this filing for the first time. The parameters required by this system are: (1) estimated deactivation dates for each power production plant; and (2) interim survivor curves. The interim survivor curves are presented in Section 3 of Exhibit DSH 1. The estimated deactivation dates for each power production plant are outlined in Section 1 of Exhibit DSH 1, and discussed in Mr. Krall's testimony.

Q. Please discuss the use of the life-spanning system of depreciation as it applies to property in the Nuclear Production function.

A. Property installed in the Nuclear Production function prior to January 1, 1989 is depreciated using the Modified Sinking Fund system of depreciation. However, all property installed on January 1, 1989 and thereafter is depreciated using the life-spanning system. This concept was approved by the Commission at Docket No. P-880332 as part of the Company's compliance strategy for SFAS 92. This filing is the first time that interim survivor curves are presented for Nuclear Production.

Q. Please discuss modified sinking fund depreciation as it is currently implemented.

A. Modified sinking fund depreciation was first proposed by PP&L and approved by the Commission at Docket No. R-822169 as the depreciation methodology for Susquehanna SES Unit 1. The primary reason for proposing this methodology was to minimize the impact on customers' rates associated with placing Unit 1 in service. This methodology was also proposed and approved for Susquehanna SES Unit 2 at Docket No. R-842651.

Under sinking fund depreciation, the annual accrual is equal to: (1) a principal amount; and (2) an "interest" component. The principal is the annual amount that, if deposited in an interest-bearing account, would yield the original cost investment of the depreciable plant by its expected retirement date. The "interest" component is equal to the interest, compounded annually, assumed to accrue on the "principal" amount. Under sinking fund depreciation, the annual accrual gets larger each year, in contrast to straight-line depreciation, where the accrual is the same from year to year.

PP&L proposed a Modified Sinking Fund method, which used the sinking fund calculation to calculate annual accruals to the year 2000. At that point: (1) the sum of the MSF annual accruals would equal the depreciation that would have been accrued on the straight-line method; and (2) in a modification of the pure sinking fund method, PP&L proposed that annual accruals be calculated, prospectively, on a straight line basis. In that year, the MSF annual accrual would have been higher than the straight-line accrual, and the modification would therefore reduce annual depreciation expense. This method was approved by the Commission in its final order at Docket No. R-842651.

In August 1987, the Financial Accounting Standards Board issued SFAS 92 establishing accounting standards for "phase-in" plans, which were defined to include sinking fund and modified sinking fund depreciation techniques. In accordance with transition rules under SFAS 92, PP&L had until December 31, 1998 to recover the same amount of depreciation it would have accrued had the straight-line method been used since the Susquehanna Units 1 and 2 were placed in service. At that date, PP&L would have recovered, under its MSF depreciation method, approximately $197 million <u>less</u> than the straight-line method.

In order to comply with SFAS 92, PP&L filed a Petition with the Commission on November 1, 1988, requesting permission to recover the $197 million shortfall by a ten-year amortization commencing January 1, 1989. By its Order entered December 29, 1988 at Docket No. P-880332 the Commission approved PP&L's request. As a consequence, PP&L's annual depreciations, up to December 31, 1998, would consist of: (1) the annual accrual calculated on the basis of the MSF method; and (2) the annual amount of $19.7 million related to the previously described amortization. Because MSF depreciation accruals increase each year, the total of (1) and (2) would be an increasing amount each year through 1998. For example, the total for 1994 is $127,916,725, while the total for 1995 is $141,316,228. Additional increases occur each year through 1998, when the total is $192,320,977.

Q. What is the Company proposing regarding modified sinking fund depreciation?

A. The Company is proposing to include in customers' rates a levelized amount of depreciation in place of the annually increasing amount. This levelized amount would remain in effect until January 1, 1999, at which time the depreciation expense amount would decrease to the straight-line level and the amortization, approved by the Commission in 1988, would terminate. If the Company's proposal is adopted, the Company would adjust its retail rates to reflect the impact of this change to the straight line method and the termination of the amortization as of January 1, 1999.

Q. Please explain the derivation of the levelized amount of depreciation expense.

A. Section 5 of Exhibit DSH 1 contains a schedule showing total expected depreciation expense for the years 1995 through 1998 using the currently-approved modified sinking fund system of depreciation. The schedule is split into two sections: (1) depreciation applicable to plant in service in Account 101; and (2) depreciation applicable to plant in service in Account 182.3.

The Company expects this rate request to become effective on or about September 30, 1995. Therefore, it has calculated a levelized amount of depreciation by including three months of expected 1995 depreciation and 12 months from each of the years 1996 through 1998. This total amount was then levelized over 39 months for an annual amount of $172,729,583.

Q. Please explain the reason for including depreciation on property in Account 182.3.

A. Susquehanna SES Unit 1 was placed in service on June 8, 1983 and Susquehanna SES Unit 2 was placed in service on February 12, 1985. In accordance with Commission policy, the Company placed one-half of common plant in service with Unit 1 and the remaining one-half of common plant with Unit 2. During the period from June 8, 1983 until February 12, 1985, the Company continued to accrue AFUDC on the one-half of common plant which remained in Construction Work in Progress. This accrued AFUDC amounted to $28,502,322.

In 1986, the Federal Energy Regulatory Commission ("FERC") ordered the Company to remove this amount from Plant in Service and record it in Account 186 - Miscellaneous Deferred Debts. It was subsequently transferred to Account 182.3 - Regulatory Assets in 1993. The FERC contended that all common plant should have been placed in service with the first unit. Therefore, it is appropriate that the Company include Account 182.3 with Account 101, in acordance with Public Utility Commission ratemaking practice.

Q. Why is the Company making the proposal to levelize Susquehanna MSF depreciation?

A. Traditional ratemaking policy gives the Commission broad discretion in establishing depreciation methodologies and rates. The Company is requesting that the Commission apply this discretion in a logical manner by establishing a "normalized" level of depreciation over the 39 months following the expected decision in this filing. The Company's proposal to levelize sinking fund depreciation for these remaining 39 months, in essence, is equivalent to using a straight line method of depreciation over this period. As such, the proposal will not result in the recovery of any additional depreciation over this period. Moreover, the Company's proposal will eliminate the large annual increases in depreciation expense that arise under the current sinking fund method. Elimination of these substantial cost increases should enable the Company to minimize future base rate increase requests which otherwise could be necessary.

Q. Please explain the Company's proposal regarding the amortization of certain General Plant accounts.

A. The General Plant accounts which the Company is proposing to amortize are those which account for Office Furniture, Tools and Equipment. At test year ending September 30, 1995, these items comprise less than six-tenths of one percent of the total investment in Plant in Service. This property is characterized by a relatively low average cost per item, is generally subject to movement throughout the Company's system, and requires an inordinate amount of administrative effort to maintain records by retirement units.

Q. Please explain the implementation of the proposed method.

A. The Company is proposing that these items would be recorded on its books at the plant account and vintage level. There would be no attempt made to develop and segregate costs by retirement unit. Retirements would be posted to the Company's books automatically upon full amortization of a vintage group of property, therefore, eliminating the necessity for actual retirement reporting.

Q. How is the Company proposing to handle removal costs and salvage incurred upon disposition of this property?

A. The Company is proposing to treat the net current year removal and salvage as a component of the current year additions. This is based on the rationale that removal and/or salvage applicable to this property are expected to be negligible.

Q. Would you summarize why the Company is proposing a change from depreciation accounting to amortization accounting for this property?

A. The large volume of low average cost items represented by this property requires an inordinate amount of administrative effort to properly record, retire and track this property. By switching to amortization accounting for this property, the Company will be able to more efficiently and cost-effectively process the plant transactions related to this property.

Q. Does this conclude your statement of direct testimony?

A. Yes, it does.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 5

Direct Testimony of Douglas A. Krall

Docket No. R-00943271

Q. Please state your full name and business address.

A. My name is Douglas A. Krall. My business address is Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsylvania Power and Light Company (PP&L or the Company). My title is Manager-Integrated Resource Planning.

Q. What is your educational background?

A. I graduated from Stevens Institute of Technology in Hoboken, New Jersey in 1973 with a Bachelor of Engineering degree in Mechanical Engineering. I have completed additional courses in Business Administration at Muhlenberg College in Allentown, Pennsylvania.

Q. Are you a registered professional engineer?

A. Yes. I have been a Registered Professional Engineer in the Commonwealth of Pennsylvania since 1977. My registration number is PE-026733-E.

Q. Please describe your professional experience.

A. I joined PP&L's Mechanical Engineering Department in 1973 as an Engineer-Level I. In 1974, the engineering functions were restructured and I became a member of the Power Plant Engineering Department. In 1975, I was promoted to the position of Engineer-Level II, and in 1978 to the position of Project Engineer within that department. Later in 1978, I transferred to the System Planning Department and in 1981 I was promoted to the position of Senior Project Engineer. In 1984, I was promoted to the position of Manager - Generation Development Planning within System Planning. Among the duties under that position are responsibility for analyzing capital investment needs and opportunities at PP&L's existing fossil and hydro generating units consistent with the value of those generating units within an integrated resource plan and, also, supervision of the development of the Company's annual construction budget. In December, 1994, that function was merged with our energy and capacity resource planning function and I became responsible for both with the title Manager-Integrated Resource Planning.

Q. Have you ever testified before the Pennsylvania Public Utility Commission previously?

A. Yes, on behalf of Interstate Energy Company, a subsidiary of PP&L, in regard to its application to provide service in the transportation of natural gas to existing customers (Docket No. A-140200).

Q. Please provide a summary of your testimony.

A. My testimony will address:

1. The 1994-95 Construction Budget, the 1995-96 Construction Budget, and adjustments made to both budgets to develop the estimates of electric plant additions and retirements reflected in the future test year.
2. The Company's responses to Regulations II-B-1 (electric plant held for future use), and II-B-2 (pollution control work in progress).
3. Deactivation dates assigned to fossil and hydro generating stations for depreciation accounting purposes.
4. Activities undertaken by the Company to upgrade the capability of its generating plants to use coal.

Q. What Exhibits are you sponsoring?

A. I am sponsoring Exhibits DAK 1, DAK 2, DAK 3 and DAK 4. In addition, as noted above, I am responsible for and will sponsor the Company's responses to Commission Regulations II-B-1 and II-B-2.

Q. Please describe Exhibits DAK 1 and DAK 2.

A. Exhibit DAK 1 is a copy of PP&L's 1994-1995 Construction Budget. Exhibit DAK 2 is a copy of PP&L's 1995-1996 Construction Budget. At PP&L, a construction budget is prepared annually to identify capital requirements of the Company and to establish a basis for financial and manpower planning. The Construction Budget is prepared within the Integrated Resource Planning department with input from many other departments. It is reviewed with the Board of Directors in October of each year at which time the Board provides its approval.

Q. With regard to Exhibit DAK 1, would you please explain Table 2-1, appearing on Page 2-3?

A. Yes. It shows, by years, the estimated construction expenditures which are required during the five-year period, 1994-1998, for the development and expansion of PP&L's electric facilities. This information is presented in total and for each of the several major classes of facilities.

Q. Will you please explain Item 1 in Table 2-1 on Page 2-3?

A. Item 1 reflects budgeted expenditures during the five-year period necessary to place new generating plants in service. As described in Chapter 3 of Exhibit DAK 1, PP&L does not have a near-term need for new generating capacity. Consequently, no dollars are included in the budget for that purpose.

Q. What is covered by Item 2, "Existing Generation - Nuclear"?

A. This item covers facilities and equipment at the Susquehanna power plant which are required to meet regulatory requirements and modifications necessary to maintain and improve operation of the Susquehanna units.

Q. What is covered by Item 3, "Existing Generation - Fossil and Hydro"?

A. Most of the dollars shown in this category are for additions and modifications to PP&L's existing non-nuclear generating stations to bring them into compliance with environmental regulations. Additional expenditures are required for replacement of equipment to maintain normal operation of these plants. Some expenditures are also included for improvement projects to increase availability, to reduce operating and maintenance expense, and to improve working conditions including safety related items.

Q. What is covered by Item 4, "Bulk Power"?

A. This item includes 230 kV and 500 kV transmission lines, 500-230 kV substations, and capacitor installations at 230 kV and 500 kV switchyards. These facilities provide the means for connecting the large generating stations on the PP&L system to the load centers. They also provide the means for interchange of economic energy among companies, and complement the installed capacity of interconnected companies by providing a means of importing or exporting capacity and energy among interconnected systems in times of operating emergencies.

Q. What is covered by Item 5, "Regional Supply"?

A. These are facilities necessary to connect the area distribution facilities to the bulk power supply system. They include new 230-69 kV transformer capacity, new and reconstructed 138 and 69 kV lines and 69 kV capacitor installations.

Q. What is covered by Item 6, "Area Supply" and Item 7, "Revenue Work"?

A. The budget for area supply facilities covers the expansion and development of the distribution system with respect to establishing new 138-12 kV and 69-12 kV substations, increasing transformer capacity at existing substations, adding 12 kV lines and terminals at existing 138-12 kV and 69-12 kV substations, installing capacitors at substations and on distribution lines, and converting distribution systems from 4 kV to 12 kV.

Other work in this category includes replacement of deteriorated or obsolete equipment, relocations due to highway improvements or other rights-of-way interferences and modifications to facilities to meet improved health and safety standards required by OSHA.

Item 7, "Revenue Work" includes line extensions to connect new loads, street lighting additions and modernization, and purchases of distribution transformers and meters for near-term use which are considered to be in service at the time of receipt.

Q. Please explain Item 8, "Sites and R/W".

A. The difficulties in acquiring land for use with generating stations and substation sites or for transmission line rights-of-way require action well in advance of the actual construction period. This item reflects the estimated expenditures for this activity in the 1994-1998 period.

Q. Please explain Item 9, "Buildings".

A. The dollars shown in this category are identified for building projects. These funds are required to replace old, deteriorated buildings requiring major repairs; to comply with OSHA regulations; to provide adequate space to meet personnel requirements; and to correct inefficient work operations. The new buildings and additions or modifications to existing buildings represent the minimal requirements to meet the user departments' space needs.

Q. Please explain Item 10, "Other".

A. This category includes the purchase of office furniture and equipment, small tools, communications facilities, projects requiring small amounts to complete, and computer software applications which exceed $5,000,000.

Q. Below the subtotal titled "Total New Construction" is an item titled "Nuclear Fuel Purchases". Could you please explain what is covered under that item?

A. This item sets forth nuclear fuel purchases estimated for the 1994-1998 five-year period. Arrangements were completed in February, 1982 to establish a trust which enables the Company to lease its 90% share of nuclear fuel for the Susquehanna units to a maximum of $200 million. Under these arrangements, the nuclear fuel purchased by the Company is immediately sold to the trust -- up to the maximum of $200 million -- and leased back.

Q. Does Exhibit DAK 2 provide information of the same type and in the same format as Exhibit DAK 1?

A. Yes, it does.

Q. Will you now please describe and explain Exhibit DAK 3?

A. This exhibit sets forth adjustments in estimates of 1994 and 1995 additions to, and retirements from, electric plant. A summary of all such adjustments is shown on Page 3 of Exhibit DAK 3.

Q. Will you please explain the need for these adjustments?

A. The estimated construction budget, as presented in Exhibit DAK 1 and DAK 2, is prepared annually to identify the capital requirements of the Company and to establish a basis for financial and manpower planning. It also provides early identification of projects in order to facilitate an orderly process of engineering, construction and long-term system development.

Accordingly, the electric plant additions and retirements shown on Table 2-6 (Page 2-8) of both Exhibits DAK 1 and DAK 2 are only estimates of these quantities developed prior to the end of 1993 and 1994, respectively, in order to provide management with information for an orderly process of budget approval. The accuracy of these data is sufficient for the Company's budgeting process and other processes such as calculating depreciation levels, estimating outside financing needs, work scheduling and manpower planning, and other management functions.

However, it was recognized that a more detailed estimate of electric plant additions and retirements was required to develop data for the future test year in this rate case. Therefore, adjustments were made to reflect changes which occurred between budget preparation and development of the future test year data. Such adjustments are summarized by class of property on Page 3 and listed in detail on Pages 4 through 18 of Exhibit DAK 3. These adjustments represent changes to amounts included in the construction budget for exclusion of removal costs and salvage, to account for project deferrals or cancellations, and to properly reflect the latest and most accurate information.

A summary of estimated retirements by class of property is shown on Page 22 of Exhibit DAK 3.

Q. How were the adjusted electric plant additions and retirements contained in Exhibit DAK 3 used in developing PP&L's rate base claim?

A. The adjusted electric plant additions and retirements contained in Exhibit DAK 3 were used in the development of Total Electric Plant as set forth in Exhibit Future 1.

Q. Mr. Krall, do the construction budgets set forth in Exhibits DAK 1 and DAK 2, as adjusted by Exhibit DAK 3, represent, in your opinion, a necessary investment in facilities by PP&L?

A. Yes. The construction budgets are the result of careful engineering studies, extending over many months, and take into account the coordination of planning in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) and Mid-Atlantic Area Reliability Council (MAAC). They reflect PP&L's best estimate of the generation, transmission and distribution facilities needed to supply reliable and economic service both now and in the future. They also consider the need to provide new and upgraded general plant facilities which are necessary to maintain and where appropriate, improve the efficiency of operating forces. I believe it is reasonable and represents a prudent level of investment in the years 1994-1999.

Q. Please refer to the responses to Regulations II-B-1 and II-B-2. Were they prepared by you or under your supervision?

A. They were prepared under my supervision.

Q. Please explain PP&L's response to Regulation II-B-1.

A. Regulation II-B-1 relates to plant held for future use. No rate base claim for plant held for future use is being made in this filing. In the alternative, PP&L is requesting approval to accrue a return equivalent to the applicable AFUDC rate on these investments and to include the accrued amount as part of its plant in-service at the time such plant is placed into service.

Q. In the case of land held for future use, why has PP&L acquired these interests?

A. This land has been acquired because it was prudent and necessary to do so. PP&L will need a number of new sites and rights-of-way to accommodate the needs of our customers in the coming years.

The conditions which produce growth in electrical demand will also result in expansion of land occupancy. Residential, commercial and other construction in an area may render it more costly or disruptive to the community to purchase land at the last possible moment. When a need can be identified, it is in the community interest to purchase land well in advance and record the land or right-of-way purchase. This provides the community with an awareness of PP&L's plans for the area.

Another consideration is that the necessary land or right-of-way may not be available when needed in the future, which may require significant changes in the overall plan and could be more costly to customers.

Allowance must be made for local planning discussions, for negotiations, for siting approval by the Commission and for possible condemnation proceedings. Needs must, therefore, be anticipated as far in advance as possible and the necessary steps taken to acquire essential land and easements.

Q. Please explain Attachment II-B-2.

A. Attachment II-B-2 relates to construction work in progress. It is a multi-page document which identifies work in progress on pollution control projects as of September 30, 1994 and September 30, 1995.

Q. Please explain the pollution control construction work in progress contained in Attachment II-B-2.

A. Pages 1 through 7 of Attachment II-B-2 identify the various projects for pollution control facilities on which construction work is in progress. This work is required to meet the Pennsylvania Department of Environmental Resources (DER) air and water pollution regulations and, also, the requirements of the 1990 Federal Clean Air Act Amendments. Work is being done at the following five locations which are owned and operated by PP&L: Brunner Island, Martins Creek, Sunbury, Holtwood and Montour Steam Electric Stations. Also included is PP&L's share of work which is required at the jointly-owned Keystone and Conemaugh generating stations. The list of projects represents work required at these plants for improvement of particulate collection efficiency; for burners to reduce emissions of oxides of nitrogen (NOx); for closure (cover soils, grading, drainage and seeding) of existing ash disposal facilities which do not comply with new regulations; for installation of waste treatment and disposal facilities to comply with applicable regulations; and equipment to reduce emissions of sulfur dioxide.

Pages 1 through 4 of Attachment II-B-2 summarize the actual expenditures as of September 30, 1994, the estimated expenditures as of September 30, 1995, the total estimated cost, the estimated retirements and the expected completion dates for the pollution control projects included in construction work in progress as of September 30, 1994.

Pages 5 through 7 provide information for the pollution control projects included in construction work in progress as of September 30, 1995.

Pages 8 through 46 are copies of the front page of each Expenditure Requisition for these pollution control projects.

Q. **What is the relationship between Attachment II-B-2, pollution control construction work in progress, and total electric plant contained in Exhibit Future 1?**

A. The estimated expenditures at September 30, 1995 were used to develop Schedule C-3 in Exhibit Future 1.

Q. **Mr. Krall, Mr. Hoch has testified that the deactivation dates for the calculation of depreciation for fossil and hydro power plants were provided by you. Is that correct?**

A. Yes, it is. Exhibit DAK 4 is a tabulation of the dates which were provided to Mr. Hoch.

Q. **Could you please describe the rationale for these dates?**

A. The selection of deactivation dates for fossil and hydro generating plants requires consideration of a number of engineering, regulatory, and economic factors. Each of these factors involves a significant amount of uncertainty and, consequently, a considerable amount of judgment. The deactivation dates provided in Exhibit DAK 4 are engineering judgments which balance the following principal factors:

1. Finite lives of equipment.
2. Current age and service history of equipment.
3. Increasingly strict environmental regulation.

Q. **Please describe the changes which PP&L is proposing to the deactivation dates which are currently on file with the Commission?**

A. PP&L is proposing changes to the deactivation dates of fossil generating units at five locations and hydro units at two locations. First, PP&L is proposing to shorten the remaining lives of coal-fired generating units at Holtwood (Unit 17), Martins Creek (Units 1 & 2), and Sunbury (Units 1, 2, 3, & 4) by amounts that vary from six to twelve years and result in a common deactivation date of 2003 for all of these units. The proposal is based on the following factors:

1. The in-service dates of these units range from 1949 to 1954, which makes them currently between 40 and 45 years old. Given that power plant equipment of that vintage was typically designed for 30 to 40 years of operation, it is not surprising that significant equipment replacement needs are being identified.
2. These relatively old power plants operate at lower temperatures and without some of the design features of newer plants and, consequently, produce electricity less efficiently than newer plants.
3. A significant number of environmental issues are expected to affect power plants in general and coal-fired power plants in particular around the year 2000. These include the following:
   - The second phase of SO_2 reduction requirements associated with the acid rain program in the 1990 Clean Air Act Amendments, which become effective on January 1, 2000, will require additional SO_2 control measures at those units.
   - NOx reduction requirements are expected to be imposed under Title I of the 1990 Amendments. Interim reductions are expected to be required in May, 1999 with final reductions necessary to achieve ozone attainment in the Northeast expected in May, 2003. The dates are subject to completion of the regulatory process, and the need for and extent of reductions are subject to photochemical grid modeling which is not expected to be complete until 1997.
   - Reductions in emissions of air toxics may be required in 2003 under Title III of the 1990 Amendments. The need for and extent of any reductions will be determined by studies being conducted by EPA and not expected to be complete until the end of 1995, at the earliest. The

2003 compliance date anticipates a regulatory process of several years and a lead time for compliance activities prior to the compliance date.

4. These generating units are individually relatively small (net generator ratings are between 73 MW and 150 MW) meaning there are few economies of scale to make equipment replacements and environmental retrofits less economically burdensome.

It is our judgment that the combination of these factors makes the continued operation of these units beyond this time frame less certain than it was thought to be in 1988 when the current deactivation dates were established. PP&L also proposes to advance the deactivation dates of diesel-generators and combustion turbine-generators at Martins Creek and Sunbury to 2010 and 2003, respectively. This equipment provides black start capability for those steam stations and should carry consistent deactivation dates.

Q. What other changes does PP&L propose?

A. PP&L is proposing to extend by five years the deactivation dates associated with PP&L's shares of each of the jointly-owned stations at Keystone (Units 1 & 2) and Conemaugh (Units 1 & 2). Although these are coal-fired power plants and subject to the same environmental issues described previously, they are newer, much larger, and more efficient plants. The extension of these dates is consistent with commitments that have been made or are being considered regarding acid rain compliance at both locations. PP&L also proposes to extend the deactivation dates of diesel-generators at Keystone and Conemaugh by five years in order to be consistent with the steam station operations which that equipment supports.

Q. What changes does PP&L propose to the deactivation dates of hydro-electric stations?

A. As Mr. Hoch has described, PP&L is proposing to change its depreciation method for hydro plants to a life span methodology. Accordingly, deactivation dates must be established for these plants. PP&L is proposing a deactivation date of 2034 for Wallenpaupack and 2044 for Holtwood. These dates reflect the Company's intent to continue to maintain and operate these facilities, and that the current FERC licenses (which expire in 2004 and 2014) will each be renewed for 30 year periods.

Q. Does PP&L propose any other changes to the deactivation dates previously filed and approved by the Commission?

A. No other changes are proposed.

Q. Are there factors which might cause PP&L to change the proposed deactivation dates at some point in the future?

A. Yes. As equipment replacement needs come into sharper focus and the various environmental issues previously discussed are resolved, the deactivation dates set forth in Exhibit DAK 4 could be accelerated or extended. Nonetheless, those dates are based on the best information available at the time and, in my view, represent reasonable estimates for depreciation purposes.

Q. Has PP&L undertaken activities to upgrade the capability of its generating plants to use coal?

A. Yes, PP&L has and continues to upgrade the capability of its plants to use coal. PP&L's plans for upgrading its coal-fired generating plants identify work totaling $766 million which is either necessary to maintain the condition of and continue the operation of coal-fired plants, or is economically justified to increase the capacity and availability of those plants. Projects include the replacement of deteriorated equipment in order to maintain availability, the addition of equipment to comply with regulations and thereby permit the plant to continue to operate at capacity, and the addition of equipment to increase capacity or improve availability. In the latter category, examples are the addition of monitoring systems to anticipate and avoid equipment failures, and the purchase of critical spares to reduce outage times.

Q. Does that complete your direct testimony?

A. Yes, it does.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 6

Direct Testimony of John J. Slivka

Docket No. R-00943271

Q. Please state your full name and business address.

A. John J. Slivka, Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsylvania Power & Light Company (PP&L or the Company) in its Marketing & Economic Development Department as Manager-Market Research.

Q. What are your duties as Manager-Market Research?

A. I am responsible for the overall direction of the functions of the Market Research Section within the Marketing & Economic Development Department. In this capacity, I direct the forecasting of customer energy sales and peak demands. In addition, I oversee the collection of load research data and the development of customer and rate class hourly demands. I also manage and direct customer opinion market research.

Q. What is your educational background?

A. I graduated from Muhlenberg College in 1967 with a Bachelor of Science in Mathematics; from Lehigh University in 1971, with a Master of Science in Mathematics; and from Lehigh University in 1980 with a Doctor of Philosophy in Mathematics.

Q. Please describe your professional experience.

A. I was employed by PP&L in 1969 as a Mathematician in the Operations Research Section of the Company. My responsibilities were to design systems and computer programs for scientific and engineering applications. In 1978, I assumed the position of Senior Mathematician on the Corporate Energy Council Planning Staff within the System Planning Department. My responsibilities in that position were to provide analytical support to the Corporate Energy Planning Council.

In 1980, I joined the Rates & Market Research Department. In 1981, I assumed the responsibilities of Manager - Systems & Technical Analysis within the Rates & Market Research Department. I had responsibilities for the development of analytical techniques and systems designed to support the load research, forecasting and customer research functions. In 1985, in addition to the responsibilities for the Systems & Technical Analysis Section, I assumed responsibility for the Customer Research Section. The Customer Research Section had responsibility for market research and load research. In 1989, I assumed my current position.

Q. Dr. Slivka, what is the purpose of your testimony?

A. The purpose of my testimony is as follows:

- To explain the development of the Company's forecast of customer sales and peak demands;

- To sponsor and explain the annualization of sales and base rate revenues as summarized on Schedules D3 of Exhibits Historic 1 and Future 1; and

- To explain the derivation of customer load data used to develop the demand allocators employed by Mr. Kleha in his cost of service studies.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I am sponsoring Exhibit JJS 1 which consists of four pages. The first three pages set forth the Company's forecast of annual sales by customer class for the period 1994-2014. Page 4 of Exhibit JJS 1 provides aggregate peak load data for the same period.

Q. Please describe the development of the sales forecast contained in Exhibit JJS 1.

A. Different analytic techniques are used to forecast sales for short-term (two years) and long-term (three to twenty years) periods. PP&L develops the short-term forecast using a number of different forecasting techniques, input from PP&L's Operating Regions, knowledge of current economic conditions, and judgment. The techniques used for the sales forecast are basically time series analysis, econometric analysis, judgmental analysis, and turning point analysis. All computerized techniques use a common historic database.

PP&L's long-term sales forecast is based primarily on the point estimates produced by econometric forecasting. Econometric methods are utilized to quantify the interrelationships between electric sales and those economic variables affecting sales.

These relationships are expressed in the form of mathematical equations which are solved over a future period to determine future forecasted values. The PP&L computer econometric model relates sales by class of customer to population, employment, disposable income, and production levels.

Q. In your prior response, you alluded to various forecasting techniques. Please elaborate.

A. The following five methodologies are currently used by PP&L to develop its sales forecast:

- ***Box-Jenkins***

  The Box-Jenkins method analyzes the relationship of sales to the weighted sums of past sales and/or forecast errors. This enables Box-Jenkins to capture short-term fluctuations and cycles in sales.

- ***Econometric***

  This forecasting method is based on an econometric model developed by PP&L. This quarterly model produces forecasts by customer class for electrically-heated homes, general residential service, and commercial service. For the industrial class, the forecast is made for two-digit SIC groups with non-linear historical trends. This model is able to capture the short-term and long-term relationships between sales and other variables such as interest rates, incomes, population, production indices, etc.

- ***Exponential Smoothing***

  Exponential smoothing is a time-trend method which assumes there is some permanent deterministic pattern across time. At PP&L, this method is used on time series which show a distinct linear pattern.

- ***Demographic***

  This method utilizes demographic data to forecast residential and commercial sales. This method incorporates population, dwelling unit, employment, and income estimates for the forecast horizon.

- ***Turning Point***

  This method involves a turning point technique which projects the effects of future economic recoveries and recessions on industrial sales. A relationship is developed between the average length of past economic cycles and sales. This relationship is then applied to expectations for future cycles.

The forecasts produced by each of the above methods are then compared, differences discussed, and a consensus forecast developed. Because four of the five methods produce only short-term forecasts, the emphasis for long-term sales is placed on the econometric forecast.

Q. How was the sales forecast set forth in Exhibit JJS 1 used in this rate filing?

A. The sales forecast was used to develop projected future test year sales and revenues.

Q. How did you develop the peak demand forecast set forth on page 4 of Exhibit JJS 1?

A. Two methods are used to develop the summer and winter peak loads shown on page 4 of Exhibit JJS 1, a contribution-to-peak method and a system peak method.

For both the summer and winter peaks, the contribution-to-peak method uses regression analysis to determine the relationship between each class' contribution to system peak loads and its annual energy sales based on historical data. The relationships are then applied to a forecast of annual rate class energy sales to develop the forecasted contribution-to-peak for each class, which are then aggregated to derive the forecasted summer and winter system peaks.

The second method uses regression analysis to estimate the relationship between historical peaks and energy sales on a total system basis. The results of that analysis are then applied to a forecast of annual system sales to develop the forecasted annual system summer and winter peaks. The final forecast of system peaks is an average of the two methods described above.

Q. Schedules D3 of Exhibit Historic 1 and Future 1 reflect annualizations of sales and base rate revenues for the historic and future test years. Please explain how those adjustments were developed.

A. The annualization adjustment of sales and base rate revenues for the historic year ended September 30, 1994 has two components—one accounts for changes in the number of customers over the test year, and the second accounts for changes in usage. The adjustment for the change in number of customers as reported for the year by rate class was determined as follows: the change in customers from September 30, 1993 to September 30, 1994 was computed for each rate class. One-half of that change was assigned class by class and then multiplied by the average annual KWH usage per customer to obtain the sales adjustment (KWH) associated with new customers entering the rate class. The average unit base rate for each rate class was applied to the resulting KWH figures to obtain the base rate revenue adjustments.

The second adjustment recognizes changing KWH usage levels by existing customers and was determined as follows: the average change over the past three years in average annual usage for each class was computed. One-half of the change in average use was multiplied by the September 30, 1994 year-end number of customers for each rate class to obtain the KWH adjustment. The incremental base rate for each rate class was applied to this KWH adjustment to obtain the base rate revenue adjustment. The annualization of future test year sales and revenues consisted of similar adjustments for changes in the numbers of customers and customer usage.

Q. Please explain the source of the customer load data used to develop the customer class demand allocators employed in the Company's cost of service study.

A. PP&L continuously collects load data in 15 minute intervals through recording demand meters on sample locations for customers in the residential, GS-1, GS-3, LP-4, and GH classes and for all customers on Rate Schedule LP-5 and all FERC jurisdictional customers. For the classes represented by samples of load data, the sample data are extrapolated to determine hourly demands for the entire class. These data, as obtained from PP&L's continuous load studies for the twelve months ended September 30, 1994, were used to determine the contribution of each rate class to each of the twelve monthly peaks during the historic test year. Each rate class' contribution to each of the twelve monthly system peaks is averaged to calculate the twelve coincident peak (12 CP) demand allocator for that class.

Statistical analyses indicated that average billing month energy sales are a sound basis for predicting class contributions to monthly peaks. Consequently, for the future test year, class contributions to monthly peaks were projected based on: (1) the historical relationship between monthly energy sales and peak contributions, by class, as exhibited by data for the period from January 1988 through September 1994; and (2) forecasted monthly rate class energy sales. The class monthly peak contributions determined in this fashion were used to calculate 12 CP demand allocators for each class for the future test year.

As required by Commission regulations, the Company has also presented the results of cost of service studies employing a single coincident peak methodology, based on a summer and winter peak, and a non-coincident peak methodology. The demand allocators for the single coincident peak methodology used the same kind of data explained above to determine class contributions to the Company's summer and winter peaks. The demand allocators for the non-coincident peaks require that the load data be analyzed to determine each rate class' peak on a non-coincident basis. For the historic test year, actual demand data from the Company's load survey were used to determine class non-coincident peak demands. For the future test year, non-coincident peak demands were projected based on: (1) the historic relationship between class non-coincident peak demands and class contributions to monthly peaks; and

(2) projected class contributions to monthly peaks as determined in the manner I previously described.

Q. Does this conclude your testimony.

A. Yes, it does.

PENNSYLVANIA POWER AND LIGHT COMPANY

ANNUAL SALES BY CUSTOMER CLASS

	1993	1994	1995	1996	1997	1998	1999	2000
SALES (MILLIONS OF KWH)								
EHH	5,649	5,825	5,830	5,940	6,060	6,190	6,320	6,450
GRS	5,361	5,395	5,460	5,510	5,560	5,610	5,660	5,710
RESIDENTIAL	11,010	11,220	11,290	11,450	11,620	11,800	11,980	12,160
COMMERCIAL	9,311	9,540	9,830	10,090	10,355	10,625	10,910	11,200
INDUSTRIAL	9,099	9,390	9,685	9,675	9,885	10,070	10,260	10,445
OTHER	1,524	1,565	1,645	1,685	1,380	1,410	1,450	1,480
TOTAL	30,944	31,715	32,450	32,900	33,240	33,905	34,600	35,285
YEAR-TO-YEAR CHANGE (MILLIONS OF KWH)								
EHH	132	176	5	110	120	130	130	130
GRS	35	34	65	50	50	50	50	50
RESIDENTIAL	167	210	70	160	170	180	180	180
COMMERCIAL	188	229	290	260	265	270	285	290
INDUSTRIAL	353	291	295	-10	210	185	190	185
OTHER	146	41	80	40	-305	30	40	30
TOTAL	855	771	735	450	340	665	695	685
YEAR-TO-YEAR CHANGE (%)								
EHH	2.39	3.12	0.09	1.89	2.02	2.15	2.10	2.06
GRS	0.66	0.63	1.20	0.92	0.91	0.90	0.89	0.88
RESIDENTIAL	1.54	1.91	0.62	1.42	1.48	1.55	1.53	1.50
COMMERICAL	2.06	2.46	3.04	2.64	2.63	2.61	2.68	2.66
INDUSTRIAL	4.04	3.20	3.14	-0.10	2.17	1.87	1.89	1.80
OTHER	10.60	2.69	5.11	2.43	-18.10	2.17	2.84	2.07
TOTAL	2.84	2.49	2.32	1.39	1.03	2.00	2.05	1.98

NOTE: SALES TO ATLANTIC ELECTRIC & JCP&L ARE NOT INCLUDED.
1993 VALUES ARE WEATHER NORMALIZED.

JJS 1
Page 1 of 4

PENNSYLVANIA POWER AND LIGHT COMPANY

ANNUAL SALES BY CUSTOMER CLASS

	2001	2002	2003	2004	2005	2006	2007	2008
SALES (MILLIONS OF KWH)								
EHH	6,570	6,690	6,810	6,930	7,050	7,170	7,290	7,410
GRS	5,760	5,820	5,880	5,940	5,990	6,040	6,090	6,140
RESIDENTIAL	12,330	12,510	12,690	12,870	13,040	13,210	13,380	13,550
COMMERCIAL	11,490	11,780	12,065	12,345	12,615	12,890	13,185	13,460
INDUSTRIAL	10,635	10,830	11,040	11,245	11,450	11,660	11,875	12,095
OTHER	1,515	1,550	1,585	1,615	1,650	1,685	1,720	1,755
TOTAL	35,970	36,670	37,380	38,075	38,755	39,445	40,160	40,860
YEAR-TO-YEAR CHANGE (MILLIONS OF KWH)								
EHH	120	120	120	120	120	120	120	120
GRS	50	60	60	60	50	50	50	50
RESIDENTIAL	170	180	180	180	170	170	170	170
COMMERCIAL	290	290	285	280	270	275	295	275
INDUSTRIAL	190	195	210	205	205	210	215	220
OTHER	35	35	35	30	35	35	35	35
TOTAL	685	700	710	695	680	690	715	700
YEAR-TO-YEAR CHANGE (%)								
EHH	1.86	1.83	1.79	1.76	1.73	1.70	1.67	1.65
GRS	0.88	1.04	1.03	1.02	0.84	0.83	0.83	0.82
RESIDENTIAL	1.40	1.46	1.44	1.42	1.32	1.30	1.29	1.27
COMMERICAL	2.59	2.52	2.42	2.32	2.19	2.18	2.29	2.09
INDUSTRIAL	1.82	1.83	1.94	1.86	1.82	1.83	1.84	1.85
OTHER	2.36	2.31	2.26	1.89	2.17	2.12	2.08	2.03
TOTAL	1.94	1.95	1.94	1.86	1.79	1.78	1.81	1.74

NOTE: SALES TO ATLANTIC ELECTRIC & JCP&L ARE NOT INCLUDED.
1993 VALUES ARE WEATHER NORMALIZED.

PENNSYLVANIA POWER AND LIGHT COMPANY

ANNUAL SALES BY CUSTOMER CLASS

	2009	2010	2011	2012	2013	2014
SALES (MILLIONS OF KWH)						
EHH	7,530	7,650	7,770	7,890	8,010	8,130
GRS	6,190	6,240	6,290	6,340	6,390	6,440
RESIDENTIAL	13,720	13,890	14,060	14,230	14,400	14,570
COMMERCIAL	13,735	14,015	14,280	14,545	14,835	15,100
INDUSTRIAL	12,310	12,540	12,770	13,000	13,240	13,485
OTHER	1,790	1,825	1,865	1,900	1,940	1,975
TOTAL	41,555	42,270	42,975	43,675	44,415	45,130
YEAR-TO-YEAR CHANGE (MILLIONS OF KWH)						
EHH	120	120	120	120	120	120
GRS	50	50	50	50	50	50
RESIDENTIAL	170	170	170	170	170	170
COMMERCIAL	275	280	265	265	290	265
INDUSTRIAL	215	230	230	230	240	245
OTHER	35	35	40	35	40	35
TOTAL	695	715	705	700	740	715
YEAR-TO-YEAR CHANGE (%)						
EHH	1.62	1.59	1.57	1.54	1.52	1.50
GRS	0.81	0.81	0.80	0.79	0.79	0.78
RESIDENTIAL	1.25	1.24	1.22	1.21	1.19	1.18
COMMERICAL	2.04	2.04	1.89	1.86	1.99	1.79
INDUSTRIAL	1.78	1.87	1.83	1.80	1.85	1.85
OTHER	1.99	1.96	2.19	1.88	2.11	1.80
TOTAL	1.70	1.72	1.67	1.63	1.69	1.61

NOTE: SALES TO ATLANTIC ELECTRIC & JCP&L ARE NOT INCLUDED.
1993 VALUES ARE WEATHER NORMALIZED.

Pennsylvania Power and Light Company
Annual Sales, Output, Seasonal Peaks, and Load Factor

	Sales	Output	Peaks		Load Factor
			Summer	Winter	
	(GWH)	(GWH)	(MW)	(MW)	(%)
1994	31,715	34,197	5,550	6,605	
1995	32,450	35,018	5,680	6,725	60.52
1996	32,900	35,347	5,775	6,790	60.00
1997	33,240	35,757	5,855	6,915	60.12
1998	33,905	36,464	5,980	7,050	60.20
1999	34,600	37,499	6,105	7,185	60.72
2000	35,285	38,122	6,225	7,330	60.57
2001	35,970	38,861	6,360	7,465	60.52
2002	36,670	39,616	6,480	7,600	60.58
2003	37,380	40,382	6,615	7,745	60.66
2004	38,075	41,131	6,740	7,875	60.62
2005	38,755	41,865	6,870	8,010	60.69
2006	39,445	42,609	6,995	8,145	60.72
2007	40,160	43,380	7,130	8,280	60.80
2008	40,860	44,135	7,250	8,415	60.85
2009	41,555	44,885	7,385	8,550	60.89
2010	42,270	45,656	7,510	8,695	60.96
2011	42,975	46,416	7,640	8,830	60.94
2012	43,675	47,171	7,775	8,965	60.98
2013	44,415	47,969	7,910	9,110	61.08
2014	45,130	48,740	8,035	9,255	61.07

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 7

Direct Testimony of Joseph M. Kleha

Docket No. R-00943271

Q. Please state your full name and business address.

A. Joseph M. Kleha, Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsylvania Power & Light Company (PP&L or the Company) in its Office of General Counsel as Manager - Regulatory Projects.

Q. What are your duties as Manager - Regulatory Projects?

A. I am responsible for overseeing corporate projects involving regulatory agencies. As part of this function, I review and provide technical oversight on the preparation of the Company's cost allocation and revenue requirements studies.

Q. What is your educational background?

A. I graduated from the Pennsylvania State University in 1974 with a Bachelor of Science Degree in Accounting. I also have taken specialized courses dealing with public utility accounting and depreciation. In addition, I attended the NARUC Regulatory Studies Program in the summer of 1979.

Q. Please describe your professional experience.

A. I was employed by the Pennsylvania Department of Public Welfare as Field Auditor and Institutional Collections Officer from 1974 to 1977. In 1977, I joined the technical staff of the Pennsylvania Public Utility Commission (PUC) as a Utility Rate Analyst in the Bureau of Rates and Research. In this position, my responsibilities included review of proposed retail electric rate filings and the preparation and presentation of testimony in formal rate proceedings. This testimony primarily dealt with the allowable levels and jurisdictional allocations of claimed operating revenues, operating expenses, and rate base. In July 1981, I joined PP&L as a Senior Accountant with responsibility for assembling financial data and preparing revenue requirement studies to support the Company's retail and wholesale rate filings. I was named Manager - Regulatory Projects, the position I now hold, in January 1990.

Q. Have you previously testified as a witness on cost-of-service-related issues?

A. Yes. As an analyst in the Commission's Bureau of Rates and Research, I offered testimony in the following rate proceedings:

Company	Docket No.
Duquesne Light Company	R-79010740

UGI Corp. - Luzerne Division	R-79050863
Philadelphia Electric Company	R-79060865
West Penn Power Company	R-80021082
Pennsylvania Power & Light Co.	R-80031114
Metropolitan Edison Company	R-80051196
Pennsylvania Electric Company	R-80051197

While employed by PP&L, I have offered testimony in the following rate proceedings before the PUC and the Federal Energy Regulatory Commission (FERC):

Docket No. I-900005
Docket No. P-910521
Docket No. M-00930406
Docket No. C-00935175
Docket No. C-00935403
Docket No. ER88-545-000
Docket No. ER91-322-000

Q. Mr. Kleha, briefly describe the subject matter of your testimony in this proceeding.

A. I will summarize PP&L's ratemaking practices and procedures. I will sponsor and explain the cost allocation studies for the historic test year and the future test year. I will explain PP&L's proposed Energy Cost Rate (ECR) modification regarding the ratemaking treatment of revenues that PP&L receives from capacity-related off-system sales. I will explain and support PP&L's proposal to recover the non-energy revenue requirements associated with bulk power capacity and energy agreements which terminate, specifically, the phase-out of the capacity and energy agreement between the Company and Jersey Central Power & Light Company (JCP&L). I also will explain a proposed modification to the Company's Special Base Rate Credit Adjustment (SBRCA). Finally, I will explain PP&L's proposal regarding its Electric Plant Held For Future Use.

Q. Would you briefly describe the contents of Exhibits JMK1 and JMK2?

A. Exhibits JMK1 and JMK2 respond to the Commission's Regulation IV-E-1 and present fully distributed Pennsylvania jurisdictional costs of providing service to the various rate classes at both present and proposed rates. The studies contained in Exhibit JMK1 are based on costs and operating conditions for the historic test year ended September 30, 1994. The studies contained in Exhibit JMK2 are based on costs and operating conditions for the future test year ending September 30, 1995. The objective has been to make each exhibit self-contained. Each exhibit provides a summary of the results, a computer printout of the cost allocation, and supporting schedules showing functionalization of the costs and support for the cost allocation factors used. Explanatory material with regard to methods employed and cross-referencing to Exhibits Historic 1 and Future 1, as applicable, also are included.

Q. What cost allocation method was utilized in your studies?

A. The cost allocation studies generally follow the same principles utilized by PP&L in its last base rate filing at Docket No. R-842651. As explained in Exhibits JMK1 and JMK2, PP&L employs the monthly peak responsibility demand allocation method, or 12 coincident peak method (12 CP), which is based on the average of the twelve monthly coincident class demands at the time of the system monthly peak loads. The Company believes that, for its system, this method is a reasonable and appropriate methodology for the allocation of demand-related costs. Therefore, all sections of the two exhibits, except Sections V, pertain to studies utilizing that method. Sections V present the results of studies using other demand allocation methods as required by Regulation IV-E-1.

Q. Mr. Kleha, please describe the considerations supporting PP&L's choice of the monthly peak responsibility demand allocation or 12 CP method.

A. As the Company explained in its last retail base rate case, there are four primary considerations for use of the 12 CP method.

The first is long-term stability. Abrupt changes with respect to rate matters generally are undesirable, especially changes regarding cost allocation methods. PP&L has used the monthly peak responsibility method in every Pennsylvania and Federal rate filing in which it has submitted cost allocation studies. The Commission determined that it was acceptable in PP&L's last base rate case. Nothing in this filing provides any compelling reason to discontinue its use. The comparative summary of results in Section V of Exhibit JMK2 indicates the sharply different and mixed signals that would be given to the various rate classes if other methods were used.

The second is PP&L's installed capacity obligation to the Pennsylvania-New Jersey-Maryland (PJM) Interconnection. As discussed by Mr. Sipics, the design and nature of PP&L's bulk power production and transmission system are influenced by its participation in PJM. The PJM's planned capacity requirement needed to meet its reliability objectives is defined as a levelized amount over a 12-month planning period, and each member company is obligated to provide its share of that requirement. As Mr. Sipics explains, the determination of PP&L's obligation reflects many factors including seasonal load diversities and average peak load shapes over the period. The use of PP&L's monthly peak responsibility demand allocation method is consistent with the determination of PP&L's installed capacity obligation to PJM.

The third consideration supporting use of the monthly peak responsibility demand allocation method is recognition of seasonal class diversities. Paralleling the recognition by the PJM of the benefits of PP&L's seasonal diversity on a total system basis, PP&L believes that recognition of seasonal class diversities is necessary to properly reflect those benefits among the rate classes. The monthly peak responsibility method provides for this consideration.

The fourth consideration is the scheduling of generation equipment maintenance throughout the year. As part of its participation in the PJM, PP&L must schedule planned maintenance throughout the year in coordination with other PJM member companies. The monthly peak responsibility method reflects these actual PP&L system operating conditions.

Q. Please explain your previous reference to Pennsylvania jurisdictional costs.

A. This filing is based on only the Pennsylvania jurisdictional costs to provide service; Sections III of Exhibits JMK1 and JMK2 provide the allocations of total electric department costs between the Federal and Pennsylvania jurisdictions. The result is that all costs associated with the bulk power supply services to Atlantic City Electric Company (ACE), Baltimore Gas & Electric Company (BG&E), JCP&L, and UGI Corporation, as well as the full requirements wholesale services to Citizens' Electric Company of Lewisburg, the Allegheny Electric Cooperative, Inc. and sixteen municipalities are completely excluded from PUC jurisdictional revenue requirements.

Q. How did PP&L allocate costs to its interruptible service customers in its future test year cost allocation study?

A. In its future test year cost allocation study provided in Exhibit JMK2, PP&L allocated costs to its interruptible service customers using a two-step approach. Under this approach, the Company (1) allocated total system electric production plant costs using the total forecasted system coincident peak demand contributions, including those of its interruptible service customers and (2) provided an "equivalent peaking capacity value" credit for the estimated non-firm coincident peak demand contributions of these interruptible service customers.

Q. Please elaborate.

A. Under the "equivalent peaking capacity value" approach, total system production plant costs are allocated to each customer class in proportion to the total forecasted coincident peak demand contribution of that class. After assigning the applicable total system costs to each rate schedule customer class, the amount of non-firm coincident peak demand for interruptible service customers is estimated by subtracting the customers' contracted firm demand levels from their total forecasted demand contribution. The non-firm demand of these customers, or about 287 MW, is multiplied by the value of an equivalent amount of peaking capacity. The current value of new peaking capacity, or about $300/KW, is explained by Mr. Sipics.

The resulting credit amount (about $86 million) is subtracted from the level of system electric plant in service costs assigned to those affected customer classes in relation to the amount of their applicable non-firm demand. The non-participating portion of the affected customer classes and all other customer classes then are assigned their proportionate share of the "system value" of interruptible load.

Q. Please describe the distribution plant investment studies contained in Exhibit JMK3.

A. Exhibit JMK3 contains the results of two studies: (1) the subfunctionalization of distribution plant investment and expense into primary and secondary voltage components and the classification of the secondary components into customer and demand-related costs, and (2) the development of allocators for meter investment and meter reading expense, which are used in the historic and future test year cost allocation studies provided in Exhibits JMK1 and JMK2. It should be noted that the subfunctionalization and classification of distribution plant investment and expense is based on a detailed analysis of specific PP&L plant records and cost data. The methodologies employed in the studies are explained in detail in Exhibit JMK3 and the results of these studies are reflected in Sections A and B of Exhibits JMK1 and JMK2.

Q. In classifying its distribution plant investment and expense into customer and demand-related costs, has PP&L used the same methodology as that used in its last base rate case?

A. No. The methodology used in this filing to classify distribution plant into customer and demand-related costs is different from that used in PP&L's last base rate case, which was filed in 1984. In its last base rate filing, PP&L classified distribution plant and expense by using a modified "zero intercept" method. This methodology determines the customer and demand-related cost components on the basis of <u>only</u> the cost of labor incurred to install new distribution facilities. Because the modified zero intercept method analyzes only selected distribution expenditures (labor costs) rather than all expenditures, the method is deficient in its determination of the current cost of the "minimum size" distribution system necessary to provide reliable electric service to customers. Therefore, the Company has determined that it is more appropriate to use the "minimum size system" method to identify the applicable customer and demand-related cost components.

Q. Mr. Kleha, has the Company provided cost allocation study results which show the effects of its Economic Development/Industrial Development Initiatives (EDI/IDI) revenue credits on customers' rates?

A. Yes. In a Commission-approved settlement agreement regarding PP&L's EDI/IDI programs at Docket No. R-870600, the Company agreed to provide cost allocation study results in its next base rate filing which show the effects of the EDI/IDI revenue credits on customers' rates. The requested results are provided in Section VII of Exhibit JMK2. It should be noted that the cost allocation study results only exclude the effects of the EDI/IDI revenue credits; no other changes to costs or revenues are assumed. This mechanical calculation does not purport to show the total impact of eliminating the Company's EDI/IDI programs. As explained in the direct testimony of Mr. Kasper, the availability of the EDI/IDI programs has permitted the Company to retain existing industrial customers and to attract new customers. The cost allocation study results which exclude the effects of the EDI/IDI revenue credits do not reflect any customer status changes.

Q. Please briefly describe PP&L's retail rates.

A. PP&L's retail rates consist of three principal components - base rates, the ECR and the SBRCA.

Q. What costs generally are recovered through a utility's base rates and what costs are recovered through the ECR?

A. Generally, a utility's costs associated with its investment in generation, transmission, distribution and other property devoted to public service (return on and of its investment in these facilities), as well as the costs associated with operating and maintaining this investment, are recovered through its base rates. The cost of fuel needed to generate electricity, the energy-related cost of power purchased and the energy-related component of receipts from interchange energy sales to other utilities usually are included in its ECR, to the extent that the net of these amounts varies from the level reflected in base rates.

Q. Historically, has the Company's ECR reflected only energy-related costs and receipts?

A. Yes. At the time of the ECR's initial introduction, PP&L's tariff language (like that of other jurisdictional utilities) expressly stated that the ECR was intended to reflect only energy-related costs. This approach was consistent with the formula prescribed by the Commission when it established the net energy clause (predecessor to the current levelized ECR) in 1978. At that time, the Commission issued an Order at Investigation Docket No. 214, requiring PP&L, as well as other jurisdictional electric utilities, to replace its existing fuel adjustment clause with an energy clause. The new clause prescribed by the Commission defined "Net Energy Interchanged" as "the amounts charged or credited to Account 555, excluding charges or credits for reserve capacity transactions." (emphasis added). In compliance with the Commission's Order, PP&L's ECR tariff defined "Interchange Energy Sales" as "the amounts credited to Account 555 associated with interchange energy sold, excluding capacity or demand credits." (emphasis added).

Q. Does the Company's ECR include the cost of purchases from cogeneration and small power production qualifying facilities (QFs)?

A. Yes. PP&L purchases output from QFs at rates based upon "energy-only" avoided costs and recovers the costs of those purchases through its ECR. This approach is fully consistent with the general ratemaking principles and PP&L tariff provisions that I discussed earlier. In addition, this approach is in full compliance with Commission orders approving the rates that PP&L pays to QFs and recovery of those payments through the ECR.

I would like to make two additional points regarding the purchase of output from QFs. First, PP&L is required by law to purchase this output and, at the option of the QF, must offer long-term levelized avoided cost rates. Second, PP&L makes no profit from these transactions; it recovers through the ECR only the costs of actual purchases from the QFs. Under these circumstances, recovery of payments for QF output, on a full and current basis, through the ECR is appropriate.

Q. Please describe the traditional ratemaking treatment for revenues that a jurisdictional electric utility, such as PP&L, receives from off-system energy and capacity-related sales.

A. To the extent that a jurisdictional electric utility, such as PP&L, sells energy (KWH) off-system, the revenues received for those energy sales are flowed through to customers as a credit in the ECR. I would note that the receipts from <u>all</u> of the energy sales that PP&L makes to other utilities are credited to customers through its ECR.

To the extent that a jurisdictional electric utility, such as PP&L, sells capacity (KW) off-system, the revenues received for those capacity-related sales usually are credited to customers through base rates established in a base rate proceeding or, in the alternative, all of the costs associated with that capacity are removed from retail rates through jurisdictional cost allocation in a base rate proceeding. For example, all costs associated with PP&L's long-term capacity and energy agreements were excluded from the level of retail revenue requirements established in its last base rate case. In addition, the test year level of revenue received from any capacity-related off-system sales transactions was reflected in customer rates as a credit to the level of PP&L's overall revenue requirements established in that base rate case.

Q. Has PP&L made any capacity-related off-system sales?

A. Yes. The Company has made three types of capacity-related off-system sales. They are installed capacity credit sales, output reservation sales and transmission entitlement sales. Mr. Sipics describes PJM installed capacity credit sales in his direct testimony.

Q. Please describe output reservation and transmission entitlement sales.

A. Output reservation sales usually are short-term transactions under which a purchasing utility reserves the output from a specific PP&L generating unit at a negotiated, non-refundable, demand-related (KW) reservation fee. The purchasing utility may or may not utilize the output from the reserved PP&L unit. If a purchasing utility does utilize that output, PP&L reflects the amount of revenue it receives for the actual energy delivered plus a "foregone savings" as a credit in its ECR.

Under transmission entitlement sales transactions, a PJM member utility purchases the right to use a portion of PP&L's

transmission capacity entitlement to import energy from outside the power pool. If the purchasing utility actually utilizes the reserved PP&L transmission entitlement import capability, PP&L may reflect a "foregone savings" credit in the ECR.

Q. What is the traditional ratemaking treatment for revenues received from and costs incurred for capacity-related off-system sales and purchases?

A. Under traditional ratemaking, revenues and costs associated with capacity-related off-system sales and purchases are considered base rate items and, as such, are included as a credit or charge to the overall level of a utility's base rate revenue requirements. Revenues and costs associated with capacity-related off-system sales and purchases generally are not included in the calculation of a utility's ECR.

Q. Is any portion of the revenues that PP&L receives from these sales reflected in its ECR?

A. Yes. Under the terms of an output reservation sales agreement, a purchasing utility may request the delivery of energy from a reserved PP&L generating unit. Revenue received for the actual delivery of energy obviously is energy-related and appropriately reflected as a credit in the Company's ECR. In addition, delivery of energy under an output reservation agreement could, in some instances, prevent PP&L from making other interchange energy sales. To ensure that customers are not adversely affected by the loss of these sales, PP&L determines whether alternative interchange sales could have been made and whether any customer benefits may have been lost. If interchange sales and benefits may have been lost, the Company includes a "foregone savings" component in the price that it charges for delivered energy. This foregone savings amount is included in the ECR as a credit. Thus, under PP&L's approach, retail customers are fully protected -- through the ECR, they receive all energy-related revenue including a "foregone savings" credit.

Transmission entitlement sales produce a credit that is analogous to the "foregone savings" credit associated with output reservation sales. Basically, if the purchasing utility utilizes the reserved transmission entitlement import capability, PP&L may be precluded from entering into certain interchange energy sales. To make its customers whole, PP&L calculates the value of those lost sales and reflects that value as a "foregone savings" credit in the ECR.

Q. Is any other portion of the revenues that PP&L receives from capacity-related off-system sales included in its ECR?

A. Yes. In accordance with the Commission-approved "Joint Petition For Settlement of Consolidated Proceedings" at Docket Nos. M-00900238, M-00910273, M-00920312 and M-00930406 (Settlement Agreement), effective April 7, 1994, one-third (1/3) of the revenues that PP&L receives from PJM installed capacity credit sales are included in its ECR as a credit. This credit resulted from a compromise of various competing positions advanced during lengthy litigation of PP&L's ECR over several years. The compromise resolved this litigation and provided for an interim method of calculating the Company's ECR until its next base rate case.

Q. Is PP&L proposing any modifications to the calculation of its ECR to be effective with the new tariff rate schedule charges approved in this proceeding?

A. Yes. PP&L is proposing several modifications to the calculation of its ECR. Those modifications would be effective with the implementation of the new tariff rate schedule charges approved in this proceeding.

First, PP&L is proposing to roll into base rates the test year level of energy-related energy costs shown on Schedule D-4 of

Exhibit Future 1. This roll-in will establish a new base cost of energy for the future test year. As shown on Page 6 of Schedule D-3, Exhibit Future 1, the new base cost of energy is proposed to be 17.813 mills/KWH.

Second, in compliance with a Commission-accepted ECR audit finding at Docket No. D-86E003, the Company has included in the test year level of energy-related energy costs its annual Department of Energy assessment for the disposal of spent nuclear fuel.

Third, consistent with the Settlement Agreement, PP&L is proposing to continue to include in its ECR a demand/energy allocation of its output payments to PURPA qualifying facilities (QFs). Because PP&L's payments to QFs are based on "energy-only" avoided cost rates and include no explicit or implied demand component, the Company will develop a proxy for the demand component by using the PJM Installed Capacity Deficiency Rate. The applicable annual PJM Installed Capacity Deficiency Rate is multiplied by the amount of QF capacity claimed for PJM installed capacity accounting purposes in the ECR period times 365 days. For purposes of this demand/energy allocation, the Company's customers are divided into four voltage level groups: (1) the Residential group (secondary);

(2) the General Service group (non-residential secondary); (3) the LP-4 group (primary); and (4) the LP-5 group (sub-transmission and transmission). The proxy-based demand component portion of QF output payments is allocated on the basis of customer group demand allocation factors. The remainder of the QF payments is allocated on an energy basis. These PUC jurisdictional customer group demand and energy allocators are based on test year levels of demand and energy as shown on Page 13 of Schedule D-3, Exhibit Future 1.

Q. Is PP&L proposing any other modification to the calculation of its ECR?

A. Yes. PP&L is proposing that the calculation of its ECR be modified to permit the recovery of the Pennsylvania jurisdictional portion of the non-energy revenue requirements associated with bulk power capacity and energy agreements which have terminated, in whole or in part, and have not been replaced with new agreements and/or otherwise reflected in the calculation of the Company's base rate charges. An example would be the jurisdictional non-energy revenue requirements associated with the returning capacity and energy from the phase-out of the JCP&L agreement. Presently, those non-energy revenue requirements are excluded from PUC jurisdictional customers' base rates through cost allocation assignment of the applicable rate base and operating expenses to PP&L's non-jurisdictional operations.

Q. Please elaborate on this proposal.

A. Following the Susquehanna Unit No. 1 base rate case, PP&L entered into a long-term capacity and energy agreement to sell a 945 MW "slice" of its system to JCP&L. In developing its revenue requirements claim in the Susquehanna Unit No. 2 base rate filing at Docket No. R-842651, the Company completely excluded the costs of the 945 MW "slice" of its system sold to JCP&L. In this proceeding, PP&L also excluded all revenue requirements associated with the JCP&L agreement.

On January 1, 1996, the JCP&L agreement begins to phase-out over a five-year period. That is, beginning on January 1, 1996 and each year thereafter, the 945 MW "slice" will be reduced by 189 MW until the agreement terminates at the end of the year 2000. Consequently, PP&L is proposing that the calculation of its ECR be modified to permit recovery of the non-energy revenue requirements of each returning 189 MW increment of the 945 MW "slice" beginning January 1, 1996. The amount of these non-energy revenue requirements that is included in the ECR will be allocated on the same demand basis as the proxy-based demand component of QF output payments.

Q. As the 189 MW increments of the 945 MW "slice" return, would PP&L's ECR be impacted by the availability of the capacity and energy associated with those increments?

A. Yes. As each 189 MW increment returns to PP&L, the associated energy would be used to either serve the Company's native load customers or to make off-system energy sales. In addition, the availability of the returning capacity would contribute to the Company's ability to make off-system capacity-related PJM installed capacity credit, output reservation and transmission entitlement sales. If its proposal is accepted by the Commission, the Company also will credit its ECR with 100% of the PUC jurisdictional portion of capacity-related off-system revenues received from PJM installed capacity credit, output reservation and transmission entitlement sales, net of associated PJM installed capacity credit, output reservation and transmission entitlement purchases. The net amount of capacity-related sales revenues that is included in the ECR will be allocated on the same demand basis as the proxy-based demand component of QF output payments, as shown on Page 9 of Schedule D-3, Exhibit Future 1. It should be noted that, if PP&L's proposal is accepted, revenues from all off-system capacity-related sales, net of associated purchases, and from all energy-related sales would be included as a credit in the calculation of the Company's ECR. Thus, customers would receive the benefit of these capacity and energy transactions automatically.

Q. Should the calculation of PP&L's ECR be changed if the Commission rejects the Company's proposal regarding bulk power capacity and energy agreements that terminate, specifically, the returning 189 MW increments of the 945 MW "slice of system" sale?

A. Yes. If the Commission rejects the Company's proposed ECR recovery of the non-energy revenue requirements associated with bulk power capacity and energy agreements that terminate, specifically, the returning 189 MW increments of the JCP&L agreement phase-out, the calculation of PP&L's ECR should be modified to exclude any and all benefits (revenue credits) from off-system energy and capacity-related sales. It would be inappropriate to credit the Company's ECR with the revenues received from energy and capacity-related off-system sales transactions, but to exclude the costs (revenue requirements) associated with the capacity and energy that make such sales possible. Revenues and costs associated with energy and capacity-related off-system sales should either be included or excluded from the calculation of the ECR on a consistent basis.

Q. Please describe PP&L's SBRCA tariff rider.

A. PP&L's SBRCA tariff rider became effective on April 1, 1991. It was instituted to provide a mechanism to flow through to customers, on a full and current basis, credits associated with specific one-time, non-recurring or unusual items that have reduced PP&L's non-energy related operating costs. The SBRCA presently provides for reductions to rate schedule charges for three specific items.

- A change in the method of accounting for spare parts at the Company's power plants.
- A settlement agreement between PP&L and the General Electric Company regarding construction costs at the Susquehanna Steam Electric Station (SSES).
- A firm capacity and energy agreement between PP&L and ACE.

Q. Why does the SBRCA include a credit associated with the ACE agreement?

A. As I previously explained, following the Susquehanna Unit No. 1 base rate case, the Company executed a long-term sale of a 945 MW "slice" of its system to JCP&L. Consequently, in developing its revenue requirements claim in the Susquehanna Unit No. 2 base rate filing at Docket No. R-842651, the Company completely excluded the costs of the 945 MW "slice" of its system sold to JCP&L. In addition, the Company excluded from its claimed jurisdictional revenue requirements all costs associated with a long-term agreement to sell approximately 125 MW (127 MW based on current unit ratings) of PP&L's SSES capacity and energy to ACE. In other words, the Company's jurisdictional rate base, operating expense and depreciation claims did not include the cost of the "slice" of its system sold to JCP&L or the portion of SSES sold to ACE.

The sale of SSES capacity and energy to ACE terminated on October 1, 1991. At that time, BG&E began to purchase the same SSES capacity and energy. Because the BG&E agreement replaced the ACE agreement, the Company's authorized jurisdictional revenue requirements were not affected by this sale. At the time its original SSES agreement terminated, however, ACE began to purchase approximately 125 MW (129 MW based on current winter ratings) from PP&L's wholly-owned coal units. The costs associated with this coal-fired capacity and energy agreement were included in jurisdictional base rate revenue requirements. Because this change occurred between base rate proceedings, the Company was under no obligation to reduce its base rates to reflect the effect of this Agreement. However, in an effort to minimize rate schedule charges, the Company included an equivalent revenue requirements credit adjustment in the SBRCA.

Q. Is PP&L proposing any changes to its SBRCA in this proceeding?

A. Yes. PP&L is proposing to reduce the credit presently reflected in the SBRCA by excluding that portion of the credit associated with the ACE agreement. This change is being proposed because the jurisdictional revenue requirements associated with the ACE agreement are excluded from the Company's future test year base rate revenue requirements request in the future test year cost allocation study provided in Exhibit JMK2.

Q. What is PP&L's proposal regarding Electric Plant Held For Future Use?

A. PP&L is making no request in this proceeding to include Electric Plant Held For Future Use in its future test year rate base claim. However, the Company is requesting specific Commission approval to begin accruing a return component equivalent to the applicable Allowance For Funds Used During Construction (AFUDC) rate on future use property investments and to include all accrued amounts as part of Electric Plant In Service at the time such plant is placed into service.

Q. Does this conclude your direct testimony?

A. Yes, it does.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 8

Direct Testimony of Oliver G. Kasper

Docket No. R-00943271

Q. Please state your full name and business address.

A. Oliver G. Kasper, Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsylvania Power & Light Company (PP&L or the Company) in the Rates Section of the Power Systems Support Department as Manager-Pricing and Contract Administration.

Q. What are your principal duties and responsibilities as Manager-Pricing and Contract Administration?

A. I am responsible for tariff administration which involves the development of PP&L's retail and resale electric rates, tariff rules and regulations, and ensuring the uniform administration of these rates, regulations and interpretations throughout the Company. I also direct the development of PP&L's rate design and cost of service activities.

Q. What is your educational background?

A. I graduated from Michigan Technological University in 1973 with a Bachelor of Mechanical Engineering. I am a Registered Professional Engineer in the Commonwealth of Pennsylvania.

Q. Please describe your professional experience.

A. I was employed by Westinghouse Electric Corporation in 1973 and served in the Marketing Department of the Steam Turbine Division as an Application Engineer. During this period, I was involved with all aspects of the initial design and proposal preparation for large steam turbine generator sets. I also was the technical license contact for two foreign manufacturers of Westinghouse turbine generators.

In 1976, I joined PP&L as a construction engineer for the Susquehanna Steam Electric Station. In this position I was responsible for long-term storage and maintenance for all equipment during construction, and assembly of the Unit 1 and Unit 2 turbine generator sets.

In 1978, I was named Energy Management Engineer in PP&L's Energy Conservation Department in the Northern Division. My responsibilities included energy conservation, service coordination, and marketing with PP&L's large industrial and commercial customers in the division.

In 1982, I was promoted to Senior Engineer-Research and Technical Services; later the department was renamed I&C Marketing Programs. My responsibilities included residential thermal storage heating systems research, commercial and industrial HVAC and process heating/cooling research and development, and educating PP&L's staff and customers on cogeneration.

In 1989, I was promoted to the position of I&C Marketing Manager in PP&L's Lancaster Division. My responsibilities included managing a staff of 17 people who were the direct service and marketing contacts for all industrial and commercial customers in that Division.

I was promoted to Manager-Pricing and Contract Administration in 1991, the position I now hold.

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

A. My testimony addresses four subjects: (1) pro-forma adjustments to historic test year book revenues and future test year budget revenues; (2) the allocation of the proposed increase among customer classes; (3) rate design; and (4) proof of revenues.

PRO-FORMA ADJUSTMENTS TO HISTORIC AND FUTURE TEST YEAR REVENUES

Q. Mr. Kasper, please describe the purpose of Schedules D-3 to PP&L Exhibits Historic 1 and Future 1.

A. Schedule D-3 in Exhibit Historic 1 shows pro-forma ratemaking adjustments to book operating revenues for the historic year ended September 30, 1994. Schedule D-3 in Exhibit Future 1 shows similar adjustments to budget revenues for the future year ending September 30, 1995.

Q. Will you please describe the adjustments shown on Schedule D-3 in Exhibit Historic 1?

A. Page 1 of Schedule D-3 in Exhibit Historic 1 contains a summary statement of the various adjustments made to operating revenues for the year ended September 30, 1994, as follows:

Column 1 presents revenues per book as supplied by Mr. Bernini. Column 2 is the sum of all adjustments to bring the book revenues to a pro-forma ratemaking level, which is found in Column 3. Line 5, Column 2 reflects adjustments to revenues to reflect the annualization of sales and revenues at September 30, 1994, the roll-in of the energy portion of the ECR, the roll-in of the Atlantic City Electric portion of the SBRCA, and the roll-in of the STAS into base rates. All revenues in Column 3, Line 5 are pro-forma. Total operating revenue adjustments for the year ended September 30, 1994, appear on Line 17, Column 2.

Q. Will you please describe the adjustments shown on Schedule D-3 of Exhibit Future 1?

A. Page 1 of Schedule D-3 in Exhibit Future 1 contains a summary statement of the various adjustments made to operating revenues budgeted for the year ending September 30, 1995, as follows:

Column 1 represents the revenues per budget as supplied by Mr. Berish. Column 2 is the adjustments to budget to bring the revenues to a pro-forma ratemaking level, which is found in Column 3. Line 5, Column 2 reflects adjustments to revenues to reflect the annualization of sales and revenues, the roll-in of the energy only portion of the ECR, the roll-in of the Atlantic City Electric portion of the SBRCA, and the roll-in of the expected STAS of -0.49% into base rates for the year ending September 30, 1995.

The present and proposed revenues, developed in the manner described above, were used to compute overall percentage effects of the proposed rates, typical bill comparisons, and other data regarding the Company's filing. The summary results, shown on Schedule D-3, Page 5, Exhibit Future 1, are total annual PUC revenues of approximately $2,462 million and an estimated annual revenue increase of $261.6 million or 11.7% overall, to the Pennsylvania jurisdictional customers.

ALLOCATION OF THE REVENUE INCREASE

Q. Is there a general pricing philosophy and direction that PP&L has followed in the design of rates for this case?

A. With this filing, PP&L has sought to allocate its overall revenue requirement among customer classes and to design rates in a way that moves each class towards cost of service. The degree of movement is constrained by principles of gradualism and the need to acknowledge and respond to competition in some of the Company's markets. For example, several of PP&L's largest industrial customers have production facilities in other states producing the same products. An adverse increase in the price of electricity could cause a shift of production away from Pennsylvania with a corresponding loss of load for PP&L, and reduced employment for Pennsylvania. The lost load would then shift cost responsibility toward the residential and commercial customer classes which could eventually increase prices to these classes. One example of this competition is the Company's service to Amtrak. Three utilities presently supply this customer. If the price of any one utility exceeds the price offered by the other two by a significant level, that utility will experience a significant loss of sales.

PP&L has recently taken steps to address this competition through our Price Response Service (PRS) and Competitive Rate Riders (CRR), recently approved by the PUC. The PRS is an experiment in marginal pricing of our product. The CRR gives the Company flexibility in pricing to competition when required.

In this rate filing, the Company has attempted to reflect both cost and value of service to establish rates which are in the overall best interest of the Company and its customers.

Q. How does PP&L propose to allocate the rate increase in this case?

A. Exhibit OGK-3, attached to this testimony, sets forth the Company's proposed allocation of the rate increase and shows the rate of return for each tariff class at present rates and proposed rates. As shown on this exhibit, the Company's allocation moves each major tariff class toward the system average return and therefore properly reflects principles of cost of service and gradualism. Competition is reflected by the better alignment of rates to cost and by providing the Company the flexibility to address individual customer competitive issues.

RATE DESIGN MODIFICATIONS

Q. Please describe the rate design modifications in PP&L's proposed Tariff No. 200, Supplement 50, Exhibit OGK-1.

A. The primary purpose of the rate design was to design rate schedules which would produce the requested rate increase when applied to estimated conditions for the 12 months ended September 30, 1995. In addition, as with the allocation of the increase we attempted to reflect cost of service and to respond to competitive conditions in the Company's markets.

Residential

Residential customers will have several options available within the proposed tariff, Exhibit OGK-1:

Rate Schedule	Description
RS	Residential Service
RTS	Residential Service - Thermal Storage
RTD	Residential Service - Time-of-Day
RW1	Residential Service With Off-peak Water Heating

Rate Schedule RS - Residential Service:

1. The customer charge is increased from $4.80 to $7.00 per month to more accurately reflect cost of service.
2. The number of KWH steps within the rate are being increased from two to three to better reflect cost of service. The first KWH step remains at 200 KWH, the second is 400 KWH.

The Rate Schedule RTS remains essentially unchanged other than rate levels. As part of PP&L's real-time pricing experiment, PP&L is proposing to install direct load control on 50 to 100 of these systems and test radio-controlled charging of the systems to better reflect real-time cost.

Rate Schedules RTD and RW1 remain unchanged except for rate levels.

General Service

Commercial and industrial customers will have several rate schedules and rate options available:

Rate Schedule	Description
GS-1	Small General Service at Secondary Voltage or Higher
GS-3	Large General Service at Secondary Voltage or Higher
LP-4	Large General Service at 12,470 Volts or Higher
L4I	LP-4 Optional Interruptible Power
LP-5	Large General Service at 69,000 Volts or Higher
L5I	LP-5 Optional Interruptible Power
LP-6	Large General Service at High Load Factor

The GS-1 rate schedule and available options remain essentially unchanged except for rate levels.

For Rate Schedules GS-3, LP-4, and LP-5 the demand charges and KWH steps within the schedules have been modified and simplified reducing the KWH steps from 4 to 3 or 4 to 2.

Q. Why is PP&L offering a new rate -- Large Power Service at Transmission Voltage Rate Schedule LP-6 -- in this filing?

A. PP&L has compared its existing Large Power Service Rate Schedule LP-5 with other neighboring utilities as well as nationwide. While PP&L's rates have generally been at or near the middle of the range of utilities compared, those applicable to the very large users were found to be higher than other comparable utility rates. The new rate LP-6 was designed to correct the pricing to a more appropriate, comparable level.

Q. Are these large customers very sensitive to electric prices?

A. Yes, they are. Many of these customers are energy intensive users with multi-plant locations. They can expand and contract their operations in order to improve their cost profiles and profitability. PP&L is painfully aware of the consequences of losing large electric industrial customers and the related jobs on the economy of its service area. The LP-6 rate is PP&L's responsive attempt to prevent such a loss and hardship to the communities it serves.

Interruptible Service

Q. Please describe the PP&L's current interruptible rate options?

A. PP&L has made available to its customers a number of interruptible service options. PP&L's interruptible service options appear in its tariff as Rate Schedules IS-1, LP-4 and LP-5, and Interruptible Service by Agreement. Rate Schedule IS-1 is the interruptible option for greenhouse lighting. Under this option, customers who operate commercial greenhouses with a minimum of 300 KW of interruptible lighting agree to turn off the lighting in the greenhouses at PP&L's request. Rate Schedules LP-4 and LP-5 include an optional interruptible provision that is available to customers with a minimum of 1,000 KW of year-round interruptible load. Under this option, customers agree to interrupt load at PP&L's request for economic load control, for local and system emergencies, and for tests of their ability to interrupt. Interruptible Service by Agreement (ISA) provides for interruptible service and rates by individual contract to large customers who take service at 66,000 volts or higher. The contract includes the obligations of the customer to interrupt load when requested by PP&L.

PP&L's interruptible service provisions are an extension of PP&L's effort to encourage economic development in its service territory and simultaneously develop a resource of interruptible load. PP&L's large industrial customers had expressed an interest in alternatives to reduce their operating costs and improve their competitive position. The optional interruptible service provisions provide a market choice that customers with interruptible load can exercise. Interruptible service provisions also provide a capacity equivalent resource that can be used to meet the Company's installed capacity obligation to PJM or to permit the Company to sell installed capacity credits to other PJM members.

Q. What problems have evolved with PP&L's current interruptible service offerings?

A. When originally proposed, these rate provisions were intended, in part, to address the economic and competitive concerns of PP&L customers, some of who were at risk of closure, substantial business contractions, or relocations. Interruptible service under rates LP-4 and LP-5 were partially successful in retaining some businesses and the jobs they represent for the Company's service territory. However, to achieve this economic development benefit, it was necessary to implement a pricing structure that offered discounts from firm service rates somewhat greater than would have been indicated by quantifiable measures of the difference in costs between firm and interruptible load.

Nonetheless, PP&L concluded that such discounted pricing would be justified based on the economic development benefits to be produced which, in addition to retaining jobs, would retain industrial load for PP&L.

Since the LP-4 and LP-5 interruptible service options were introduced, several factors have changed. First, as stated in Mr. Sipics' testimony, the value of interruptible load has declined materially. This effect has greatly magnified the difference between the discounts for interruptible service offered by the Company and the discounts from firm service rates that would be justified by current cost levels. Second, because of the discounts available for electing interruptible service, otherwise non-qualifying customers have been encouraged to use on-site generation as a means of capturing marginal net benefits from lower electric rates. This trend has had the effect of materially increasing the pool of customers that could elect the interruptible service options. The revenue erosion that would result for the Company from this increased number of interruptible customers would reduce the industrial class contribution to fixed costs and, thereby, shift revenue responsibility to firm service industrial and non-industrial core customers with no corresponding benefit to the regional economy by way of business expansion or job growth. Moreover, because of the uneconomic cost-shifting that on-site generation makes possible, core customers who face a variety of competitive pressures but cannot use on-site generation to qualify for interruptible discounts would eventually see higher rates and resulting erosion of their competitive positions.

Q. How did PP&L respond to the interruptible rate problems?

A. On May 13, 1994, PP&L filed Supplement No. 40 to its Tariff which established revisions to the Interruptible Service by Agreement Rider, Rate Schedule IS-1 and the Optional Interruptible Power provisions of rate schedules LP-4 and LP-5.

These revisions would limit the availability of interruptible service to only those customers who were receiving interruptible service at the date of the filing and other customers who had entered into binding service agreements with PP&L as of a designated cut off date.

After hearings, Administrative Law Judge Michael C. Schnierle concluded that Supplement 40 is just, reasonable, non-discriminatory, and should be permitted to take effect. He also concluded that PP&L should be directed to file, with its next base rate case, interruptible service rates based upon cost of service and the value to PP&L of interruptible load, and a cost of service study which supports the proposed rates.

Q. Please summarize the rate treatment now given to PP&L's interruptible customers.

A. Under PP&L's current rate structure the customers whose loads are interruptible pay greatly reduced demand and energy charges compared to customers whose loads are firm. As an example, consider an LP-5 customer with a 10,000 KW total load and monthly energy consumption of 6,000,000 KWH. Under the historic LP-5 rate, the customer would pay monthly demand charges of $43,900 ($4.39 x 10,000 KW) and monthly energy charges of $220,530 (4.88¢ x 1,200,000 KWH + 4.43¢ x 1,000,000 KWH + 3.88¢ x 1,500,000 KWH + 3.21¢ x 2,300,000 KWH), for a monthly total of $264,530 (plus the applicable energy cost rate). Now assume that the customer selects the historic optional LP-5 interruptible rate, establishes a firm demand of 1,000 KW, and allows 9,000 KW of load to be interruptible. With a 90 percent on-peak load factor, the customer would pay a monthly demand charge of $18,240 ($9.60 x 1,900 KW) and monthly energy charges of $136,532 (3.21¢ x 760,000 KWH + 2.14¢ x 5,240,000 KWH), for monthly total of $154,772 (plus the same energy cost rate). As a result of allowing 9,000 KW of load to be interruptible, therefore, the customer in this example would save $109,758 per month. This equates to $146.34 per KW per year of interruptible load.

The exact level of savings enjoyed by any particular customer depends on that customer's classification, size, relative firm and interruptible load, on-peak load factor, and total hours use of demand. Given the current rate levels and designs, the LP-4 and LP-5 customers save roughly $140 per KW per year of interruptible load compared to what they would pay on the firm rate.

Q. Are rate reductions of the magnitude you have just described justified by cost of service or value of service principles?

A. No. Load that is interruptible for relatively few hours a year, at most, enables the supplying utility to avoid the need for generation capacity designed to meet short duration peak loads such as a combustion turbine. As explained in more detail by Mr. Sipics, the current installed cost of a combustion turbine is about $300/KW.

Q. Do PP&L's proposed interruptible rates provide discounts that are more in line with the capacity value of interruptibility to PP&L and its customers?

A. Yes. The current interruptible service options will be replaced with an interruptible load credit. The interruptible load credit will be deducted from the bill amount the customer would pay on the appropriate firm service rate. The interruptible load credit will be available for customers with at least 1,000 KW of interruptible load on firm rate schedules LP-4, LP-5, and the new LP-6. The monthly credit will equal:

- (Billing KW - Firm KW) x (On-peak Load Factor) x ($6/KW)

A customer with an on-peak load factor of 100%, would receive an annual credit of $72 per KW of interruptible load.

This annual credit of $72 per KW represents about a 50% reduction to the current average annual discount between firm and interruptible service of about $140 per KW.

For customers on LP-6 with at least 10,000 KW of interruptible load and who can reach firm power levels within 1/2 hour will receive an additional monthly credit of $2 per KW to reflect the added operating benefits of quick start capacity. PJM is currently developing plans to move toward a more market based system for energy purchases. Security services, such as quick start capacity, will likely become unbundled products in this market based system. Although the market price for quick start capacity has not yet been established, we are using $2 per KW per month to recognize a future market value. If the actual market value is significantly different, we will propose a revision to the credit.

Q. Have you changed the demand penalty for interruptible customers that do not achieve their firm power level during emergency or emergency test interruptions?

A. Yes. The demand penalty has been increased from $15.30 per KW to $25 per KW. As explained in Mr. Sipics testimony, the value of interruptible capacity, based on the annual levelized carrying charges of a combustion turbine, is about $50 per KW per year. This value is based on:

- combustion turbine installed cost of $300 per KW,
- levelized carrying charges of about 15%, and
- PJM reserve margin of about 20%.

We have assumed an average of two emergency interruptions per year, based on past experience, to determine the $25 per KW penalty that will compensate PP&L for the lost capacity value if customers fail to interrupt.

Q. Are there any other major changes being proposed for the interruptible service tariffs?

A. Yes. PP&L is proposing a cap of 500 MW of non-coincident interruptible load. This is a 12 month rolling average of the sum of the individual customers' average monthly maximum demands minus the sum of the individual contracted firm demands. On a diversified basis, this should result in a monthly peak demand reduction capability of about 300 to 350 MW.

PP&L is also proposing to change the requirements of an annual test if an actual emergency has not occurred in the calendar year. New customers on the interruptible provision will still be tested to confirm willingness and ability to perform.

ECONOMIC DEVELOPMENT INITIATIVES (EDI/IDI) AND DEMAND FREE DAYS

Q. Please describe the current EDI/IDI credits.

A. The Economic Development Initiative (EDI) credits were first made available in 1987 to PP&L's GS-3, LP-4, and LP-5 customers with loads over 500 KW. The EDI credits for existing customers are 1¢/KWH and \$2/KW for KWH and KW taken in excess of base period (generally 1986) amounts. To receive these credits, customers must have signed contracts agreeing to expand production or expand physical facilities. For new customers, the EDI credit is 1¢/KWH for energy taken in excess of 400 hours use of demand. The EDI credit program was closed out at the end of 1989. However, the credits received by eligible customers run through 1997 and are reduced to 70% of the full level in 1998, are reduced further to 35% of the full level in 1999, and are eliminated as of January 1, 2000. According to PP&L's EDI monitoring reports filed with the PUC, as of June 30, 1994, there were 451 customers on the EDI rider and those customers saved \$23.7 million a year.

The Industrial Development Initiative (IDI) credits were introduced in 1992. The terms are essentially identical to the EDI credit terms except that IDI credits are available only to industrial customers, the normal base period for calculation purposes is 1991, and the IDI rider is open to eligible customers through 1997. As of June 30, 1994, PP&L reported that there were 279 customers on the IDI rider and that their annual savings were \$2.0 million as a result.

Q. Does PP&L propose to continue the EDI/IDI credits in their present form?

A. Yes. PP&L plans to continue the rate reductions of the EDI/IDI riders through December 31, 1997. Beginning January 1, 1998, the billing adjustments calculated under these riders will be 70% of full credit and beginning January 1, 1999, the adjustments will be

35% of full credit. All provisions of EDI/IDI will terminate as scheduled on January 1, 2000.

Q. Why do you plan to continue offering EDI/IDI credits?

A. PP&L made a commitment to its customers to offer EDI/IDI credits until the year 2000. This program is not only beneficial for participating customers but also for non-participating customers and the local economy. In addition, numerous customers made extensive capital investments to avail themselves of the benefits of these riders and, therefore, it is appropriate that the riders continue through their intended period so that these customers may realize the economic benefits of their investments.

Q. How would eliminating the EDI/IDI riders before their scheduled termination date affect participating customers?

A. Customers based their investment decisions on the existence of the EDI/IDI programs through the scheduled period. Eliminating EDI/IDI credits before the designated phase-out would adversely affect the economic viability of numerous customer operations. For example, a manufacturer of glass base plates for television picture tubes has added electric glass melting to two of its three furnaces, one in 1989 and the other in 1994. Electric glass melting is scheduled to be added to the third furnace in 1996. Each addition increases the energy consumption by 20,000,000 KWH and requires two additional production lines. The customer could not have justified the electric glass melting or the new production lines (which added manufacturing jobs) without the EDI credits continuing through 1999.

Q. Does the continuation of EDI/IDI imply that non-participating customers will have to pay higher rates?

A. No. The purpose of the EDI/IDI program is to induce expanded output and greater electricity use than would otherwise have occurred. To the extent that the programs have been successful in accomplishing its purpose, customers on the EDI/IDI rate riders can enjoy substantial benefits while, at the same time, other customers are better off than they would have been without the EDI/IDI credit programs.

Q. Please explain how non-participating customers are better off than they would be without the EDI/IDI programs.

A. While customers receiving EDI/IDI rider discounts are better off than they would have been under a standard rate structure, non-participating customers also benefit from these rates. EDI/IDI rates cover the marginal costs of providing the service and contribute to fixed costs. The capital costs of the existing base load nuclear and coal generating units are fixed, and regardless of the demand for electricity, each additional unit of energy sold from these base load units reduces the average fixed costs per unit. The additional load on the system that results from economic development rates spreads the utility's fixed costs over a broader base, thus keeping individual customer rates lower than would otherwise be the case.

Q. Have you performed any analysis that illustrates how all customer classes benefit from the EDI/IDI programs?

A. Yes. Exhibit OGK-4, attached to this testimony, summarizes an analysis that illustrates the effects of the EDI/IDI programs on non-participating classes. The analysis centered on a sample of 7 LP-4 customers and 13 LP-5 customers who would have either relocated out of the PP&L service territory or would have gone out of business had we not offered EDI/IDI credits. The cost of service was then determined for the historic test year with the associated sales, demands, and revenues of the selected EDI customers removed from the rate class totals.

The results of the analysis show a significant decrease in rates of return for each rate class. Eliminating the sample of EDI customers caused the most substantial decrease in rates of return for the LP-5 and LP-4 rate classes, because their class demand allocation decreased. However, the rates of return for all other rate classes also declined. I would note that my analysis only considers the sample of customers described above who would have either relocated or gone out of business but for the EDI/IDI programs. It does not consider the substantial number of customers who would have opted for self-generation but for the EDI/IDI programs. As explained in Mr. Farber's testimony, the EDI/IDI programs prevented the loss of at least 300 million KWH of sales.

The reduced rates of return that occurred when the selected EDI customers were eliminated confirms that non-participants benefit from the EDI/IDI programs. The increase in total usage that results from the EDI/IDI programs helped to defer this rate case, and now also helps to minimize the increase needed for all customer classes when filing this rate case.

Q. Now, turning our attention to another economic development initiative offered by PP&L--Demand Free Days. Please explain this billing option.

A. In January 1986, as a means of further encouraging economic development in our service territory, PP&L implemented a Demand Free Days billing option for customers having a monthly maximum demand of 10,000 KW or greater. Eligible customers could pre-select two weekdays per week, from Tuesday to Friday, as Demand Free. The demand created by the customers on the pre-selected days would not be used for billing purposes.

This option was expanded in July 1992 to include three Demand Free Days and also extended to customers having a monthly maximum demand of 5,000 KW or greater. Currently, there are 23 customers served under this option whose annual savings as a result of Demand Free Days total $2.2 million.

Q. Do you plan to continue the Demand Free Days billing option?

A. Under the Company's current tariff the Demand Free Days billing option is an experimental tariff provision. The Company proposes to retain this provision until January 1, 1998.

Q. Have customers taken advantage of the Demand Free Days billing option?

A. Yes. Of the 23 customers under Demand Free Days billing, seven customers are realizing significant energy savings. This program enables those customers to run full operations from the end of on-peak hours on Tuesday to the beginning of on-peak hours on Monday without creating a billing demand. Demand Free Days have enabled these seven customers to increase their productivity and accept business orders which otherwise may have been lost. The remaining 16 have not utilized the option extensively.

Due to the relatively small number of customers utilizing this provision and other newer available rate options, the Company is proposing to terminate this provision. However, under the specific circumstances we believe it is appropriate to maintain this provision for a limited additional period to permit customers to adequately plan for and move to other rate options in an orderly fashion.

Q. In the Company's last rate case, the Commission directed the Company to file a Susquehanna Economic Growth and Development Rate in its next base rate case. Has the Company complied with this directive?

A. Yes. The EDI/IDI and Demand Free Days option are designed to encourage incremental sales at a price to the customer which is above the Company's average marginal cost, but significantly below rates produced by application of the standard rate schedules to expanded usage of the customers. In addition, the Price Response Rate allows customers to make energy decisions based on the real-time costs of PP&L to produce the energy required by the customer. Taken together, these provisions fully address the issues raised in the Company's last rate case.

TARIFF RULE CHANGES

Q. What other significant tariff changes are proposed by PP&L in this proceeding?

A. Several changes are being proposed for various tariff rules:

- Rule 2-D was changed to indicate that interest at the rate of 11% per annum on residential accounts and 6% per annum on non-residential accounts is paid annually on all deposits made to secure the payment of bills for service.
- Rule 5-E was changed to provide the Company additional discretion to waive usage (KWH) and/or demand (KW) charges for abnormal demands.
- Rule 9-F was changed to indicate that the Company will charge the customer $7.00 for processing a returned check plus any charges assessed by a bank or other financial institution on the Company.
- Rule 9-G was added on small credit balances on inactive accounts. The Company will transfer any customer credit balance less than $1.00 from a customer's inactive account to the Company's Operation HELP program instead of refunding the credit amount to the customer.
- Rule 10-B was changed to permit the Company to terminate the supply of electric service if the customer does not pay a bill from the Company for unmetered energy, or fails to remove taps or bypasses, or refuses to reimburse the Company for costs associated with detecting, investigating, and correcting current diversion.

PROOF OF REVENUE/BILL FREQUENCY ANALYSIS

Q. Mr. Kasper, please explain the methods used to calculate the annual revenue effects of the proposed rates.

A. Bill distributions and other summaries of billing quantities for all rates were assembled for the 12 months ended September 30, 1994. Partial monthly billing was corrected to full monthly billing. Both present and proposed rates were applied to the corrected billing quantities. The results of these calculations were then used to obtain adjusted rate class revenue for the period ended September 30, 1994, and to the budgeted rate class revenue for the period ending September 30, 1995, to derive the total annual revenue effect and the effect by rate classes. Increases were also assigned to the late payment charge, to the annualized revenue adjustment and to interdepartmental revenues.

Q. Would you please explain the proof of revenue or bill frequency analysis?

A. Regulation IV-C contains a bill frequency analysis which details, by rate class, the billing units for each type of charge in PP&L's existing and proposed tariff. In Column 2, there is a summary of the annual billing units for that class. This would include total customers, total KW, or total KWHs in the specific block. Column 3 contains the price per unit at current rates. Column 4 shows the total revenue for that block. The percentage increase of the proposed rates over current rates is at the bottom of each page. It is this percentage that is used to calculate the dollar revenue increase for all classes. This filing response basically "proves the revenue" and is often referred to as a "bill frequency analysis."

Q. Have you compared customer bills before and after the proposed increase?

A. Yes. Bill comparisons for selected rate schedules can be found in PP&L's response to Regulation IV-D. Various bill comparisons were completed utilizing average usage and a selected range of residential and general service usage.

Q. Would you briefly describe the contents of Exhibit OGK-2?

A. This exhibit, which is entitled 'Digest of Proposed Changes Requested in Supplement No. 50 to Tariff Electric-PA PUC No. 200," contains a summary of the Company's filed proposed rules and rate changes. A copy of this digest has been provided to all PP&L employees who have responsibility for administration of the electric tariff.

Q. Does that complete your testimony?

A. Yes, it does.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 9

Direct Testimony of John F. Sipics

Docket No. R-00943271

Q. Please state your name and business address.

A. John F. Sipics, Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by Pennsylvania Power & Light Company (PP&L or the Company) in its Power Systems Support Department as General Manager-Power Systems Support.

Q. What are your responsibilities as General Manager-Power Systems Support?

A. I am responsible for power supply planning, day-to-day operations, and the contract sales of electricity. I also have responsibility for the Company's Environmental Management and Document Management functions.

Q. What is your educational background?

A. I was graduated from Lehigh University in 1970, with a Bachelor of Science Degree in electrical engineering. I received a Master of Science Degree in electrical engineering from Lehigh University in 1977. From 1976 through 1981, I was an adjunct lecturer in the Electrical Engineering Department at Lehigh University. I am a registered professional engineer in the Commonwealth of Pennsylvania.

Q. How long have you been employed by PP&L and in what capacities?

A. I was employed by PP&L in 1970 as an Engineer in the System Planning Department. I progressed to Project Engineer before transferring to the System Operating Department in 1974. After a promotion to Operations Coordinator in 1976, I returned to System Planning as a Senior Project Engineer and served in various sections of System Planning until my appointment as Manager-Resource Planning in May, 1989. In September of 1993, I was promoted to the position of Manager-System Operation. In November of 1994, I was promoted to my present position of General Manager-Power Systems Support.

Q. Have you previously testified in regulatory proceedings on behalf of PP&L?

A. Yes, I testified in the following regulatory proceedings on behalf of PP&L:

1994 Electric Energy Emergency Investigation - Docket No. I-00940031

Q. Mr. Sipics, would you please provide a summary of your testimony?

A. My testimony will include:

1) A brief description of PP&L's electrical system and the Company's responses to Regulations I-B-1, I-B-2 and I-B-3,
2) A discussion of PP&L's Reserve Margin and Capacity Plan, and
3) A discussion of interruptible rates and their relationship to the cost of peaking capacity.

Q. Mr. Sipics, are you familiar with the PP&L electrical system?

A. Yes, I am.

Q. Do you have before you the Company's response to Regulation I?

A. Yes, I do.

Q. Mr. Sipics, were the responses to Regulation I-B-1, I-B-2, and I-B-3 prepared by you or under your supervision and direction?

A. Yes, these responses were prepared under my direction.

Q. Please briefly describe the corporate history and service territory as discussed in Regulation I-B-1.

A. PP&L is an investor-owned electric utility headquartered in Allentown, Pa. It was founded in 1920 through the consolidation of eight electric companies. The Company provides electric service to approximately 1.2 million homes and businesses throughout a 10,000-square mile area in 29 counties of Central Eastern Pennsylvania. Principal cities in the PP&L service area are Allentown, Bethlehem, Harrisburg, Hazleton, Lancaster, Wilkes-Barre and Williamsport.

Q. Please explain and describe PP&L's electric resources discussed in Regulation I-B-2.

A. The Company's total owned and leased generation resources at September 30, 1994 were 8543 MW (winter ratings). These resources include a diversified mix of plants. About 49% of the resources are coal-fired, 23% nuclear-fueled, 19% oil-fired steam, 6% combustion turbine and diesels, and 3% hydroelectric.

Additionally, PP&L purchases output from 504 MW of non-utility generation. Attachment I-B-2 provides details about these resources.

In addition, PP&L has an integrated transmission network with more than 1100 miles of transmission lines operating at 230 kV or above, and more than 50,000 miles of lines operating at less than 230 kV.

PP&L is a member of the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM) and also shares in the jointly owned PJM-Extra High Voltage (EHV) system.

Q. Are PP&L's jointly owned units included in the resource figures shown in Attachment I-B-2?

A. Yes. These figures reflect PP&L's ownership of about 12% of the Keystone coal-fired plant and about 11% of the Conemaugh coal-fired plant, both located in western Pennsylvania. In addition, PP&L owns 1/3 of the Safe Harbor Hydro Station. The Susquehanna Steam Electric Station (SSES) nuclear units are jointly owned by PP&L (90%) and the Allegheny Electric Cooperative, Inc. (AEC) (10%).

Q. Does Attachment I-B-2 reflect resources used solely to supply PP&L's Pennsylvania Public Utility Commission (PPUC) jurisdictional customers?

A. No. PP&L supplies certain demand and energy needs for the Electric Utility Division of UGI (LU), Citizens Electric Company (CE), AEC, and 16 municipal customers. Additionally, PP&L has agreements to sell firm capacity and energy to Atlantic Electric (Atlantic), Baltimore Gas & Electric (BG&E), and Jersey Central Power & Light (JCP&L). These transactions are noted in Attachment I-B-2d and Exhibit JFS-1. As discussed in greater detail below, PP&L also makes capacity credit transactions which typically represent short term commitments to optimize the use of PP&L's resources.

Q. Could you describe each of the firm capacity and energy transactions in greater detail?

A. Yes, these transactions can be described as follows:

1) PP&L and LU entered into a power supply agreement that was effective March 1, 1993. The agreement is for a 15 year period, with an option to extend for an additional five years upon agreement by the parties. PP&L has committed to supply 100% of LU's needs above its resources throughout the term of the agreement.

2) PP&L provides 16 municipal customers and CE with all their demand and energy needs. For AEC, PP&L provides the energy needs of the Sullivan County Rural Electric Cooperative Inc. in excess of other supply sources.

3) Atlantic is purchasing approximately 125 MW (129 MW based on winter ratings) of PP&L's wholly-owned coal-fired capacity from October 1991 to September 2000.

4) The BG&E agreement involves a sale of 5.94% of the installed capacity and related energy from SSES (127 MW of capacity at current summer ratings, when both units are in-service) from October 1991 to May 2001.

5) Under the terms of a sales agreement with JCP&L, a GPU subsidiary, PP&L provides JCP&L with 945 MW (winter rating) of its electrical generating capacity and related energy through the end of 1995. This sale involves an equal percentage entitlement to capacity and associated energy from all generating units in which PP&L has an ownership or lease interest excluding Safe Harbor ("slice of system" sale). After 1995, the sale decreases uniformly by 189 MW annually until the expiration of the contract at the end of 1999.

Q. Please explain PP&L's installed capacity credit transactions.

A. Under this type of transaction, an installed capacity-deficient PJM member utility can purchase the right to claim a portion of the installed capacity of a PJM member utility that has sufficient capacity reserves in order to meet its capacity obligation under the PJM Agreement. No sale of energy is involved. According to the terms of these transactions, the selling utility retains full use of all of the units involved (except for PJM installed capacity accounting purposes) and the associated energy.

Q. Please explain and describe the response to Regulation I-B-2a.

A. Pages 1 through 4 of Attachment I-B-2a provide unit installed capacities, net generation, and related capacity factors for the historic test year, the two consecutive 12-month periods preceding the historic test year, and the future test year. The attachment also shows station fuel consumption and production expense by fuel and other operating and maintenance expense for these periods.

Q. Please explain and describe the response to Regulation I-B-2b.

A. Pages 1 through 31 of Attachment I-B-2b provide the scheduled and unscheduled outages in excess of 48 hours in duration by unit for the historic test year and for the preceding 12-month period. Projected data are provided for the future test year.

Q. Please explain and describe the response to Regulation I-B-2c.

A. Regulation I-B-2c requested a schedule of units retired during the historic test year and the future test year. PP&L did not retire any units in the historic test year and has no plans to retire any units in the future test year.

Q. Please explain the information set forth in Exhibit JFS-1.

A. Exhibit JFS-1 compares PP&L's peak load to the resources available to PP&L to meet its peak load requirement and to satisfy its installed capacity obligations to PJM for a prospective 10-year period. The comparison begins with the forecasted peak load for the winter of 1994-1995. The forecasted peak loads include the demand of PP&L's full requirement resale customers, i.e., municipal customers and CE, and its partial requirement customers, LU and AEC.

The column captioned "Net Resources At The Time Of The Peak", represents the winter rating of all generation that is owned or leased by PP&L, as adjusted for anticipated deratings and upratings, less the capacity PP&L has sold to Atlantic, BG&E and JCP&L pursuant to the capacity sale agreements I explained earlier.

The next column, captioned "Reserves At The Time Of The Peak", shows PP&L's reserves in megawatts and as a percentage of peak load reflecting the generating resources owned or leased by PP&L with the adjustments I previously described. As shown, PP&L's reserve margins are 11.1 percent, 9.1 percent and 10.8 percent above forecasted peak loads for the winters of 1994-1995, 1995-1996 and 1996-1997, respectively. Reserve margins increase gradually to a high of 14.9 percent above the forecasted 2000-2001 peak load as a result of reductions in the amount of capacity sold to JCP&L under the terms of its capacity purchase agreement with PP&L. However, beyond 2000-2001, reserve margins decline, reaching only 10.4 percent above the forecasted peak load for 2003-2004.

The next two columns show: (1) the capacity equivalence of the interruptible load anticipated to be available for PJM installed capacity purposes; and (2) PP&L's reserve margins reflecting the capacity equivalence of such interruptible load. The capacity equivalence of interruptible load recognizes the amount of capacity, including a reserve margin, that would be required to supply the interruptible load on a firm basis. For example, at a 20 percent reserve margin, 100 megawatts of available interruptible load has a capacity equivalence of 120 megawatts.

As shown, assuming that all indicated interruptible load were shed at the time of the peak, PP&L's reserve margins would increase by approximately five percentage points for the periods 1994-1995 through 1997-1998 and by a range of 4.8 (1998-1999) to 4.5 (2003-2004) percentage points during the remainder of the 10-year planning period. At the time of the forecasted winter peaks for 1994-1995, 1995-1996, 1996-1997, PP&L's reserve margins reflecting interruptible load are 16.4 percent, 14.2 percent and 15.9 percent, respectively. Reserve margins increase to a high of 19.6 percent above the forecasted 2000-2001 peak load, then decline to 14.9 percent above the forecasted peak load for 2003-2004.

The next two columns show: (1) the generation expected to be available from non-utility generators at the time of each forecasted peak; and (2) PP&L's reserve margins reflecting such generation as a resource available to meet peak demand. As shown, assuming that the anticipated non-utility generation were available at the times of the peaks, PP&L's reserve margins increase by a range of 7.6 (1994-1995) to 6.1 (2003-2004) percentage points over the reserve margins that reflect interruptible load as a capacity equivalent resource. At the times of the forecasted winter peaks for 1994-1995, 1995-1996, 1996-1997, PP&L's reserve margins are 24.0 percent, 21.2 percent and 22.9 percent, respectively. Reserve margins increase to a high of 26.0 percent above the forecasted 2000-2001 peak load, then decline to 21.0 percent for 2003-2004.

The last two columns show: (1) capacity credit sales PP&L is obligated to make during 1994, 1995 and 1996; and (2) PP&L's reserve margins reflecting such capacity credit sale obligations as a reduction in available resources. If interruptible load, non-utility generation and capacity credit sale obligations are fully reflected, as shown, PP&L's reserve margins above 1994-1995 and 1995-1996 forecasted peak loads are 15.1 percent and 18.5 percent, respectively.

Q. **Mr. Sipics, please explain the significance of reserve margins in relation to PP&L's obligation to provide reliable electric service to its customers.**

A. In order to assure reliable, reasonably continuous service to customers, an electric utility must have resources equal to its anticipated peak demands plus a reasonable reserve margin. A reserve margin must be maintained for a variety of reasons including, principally, the unavailability of generating capacity due to planned and unplanned outages and the potential that customer demands could exceed forecasted peaks. It should be noted that peak load forecasts are based on "normalized" weather and temperature conditions. Consequently, summer temperatures that are hotter than "normal" can drive peak demand above forecasted levels for summer peaking companies and colder than "normal" winter temperatures can do the same for winter-peaking companies, such as PP&L.

Q. **How can an appropriate reserve margin be determined?**

A. It is not correct to think of an appropriate reserve margin as a single figure. Given the factors and contingencies that must be balanced in assessing reserve margins, such a degree of precision is not possible and should not be attempted. Rather, an appropriate reserve margin exists within a range that is defined on the basis of accepted measures of reliability; the practicalities of adding generating resources (i.e., in units of sufficient size to capture reasonable economies of scale); load shape and duration; the need for fuel diversity; the level of control the utility has over its planned resources; and the inherent limitations of available forecasting techniques.

Q. What level of reserves marks the lower end of the appropriate reserve margin range for PP&L?

A. The lower end of the range should not be less than the reserve margin PP&L *must maintain to satisfy its minimum reserve requirement as a member of PJM.* As I will explain in more detail later, that reserve requirement, expressed on the basis of PP&L's winter peak, is approximately 12 percent.

Q. What is PJM?

A. PJM is an integrated power pool consisting of PP&L and other electric utility systems in Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and the District of Columbia. PJM is responsible for the day-to-day economic dispatch of its members' generating units and for coordinating the long-term capacity planning of the pool. PJM is part of the Mid-Atlantic Area Council ("MAAC"), which is one of nine regional electric reliability councils that make up the North American Electric Reliability Council (NERC). NERC was established after the Northeast power failure of 1965 to set policies for ensuring that its participants maintain reliable service individually and on a regional basis.

Q. What does PJM do?

A. PJM coordinates the use of all members' generating resources to meet demands on an economic dispatch basis. In this way, the generation with the lowest variable cost (primarily fuel) is used to supply load. To the extent that a member company's demand is met with another company's generation, pool accounting procedures assign costs and revenues. PJM has procedures in place to encourage each company to maintain sufficient capacity, relative to its demands, and not merely depend on the capacity of the pool to meet its native load requirement. This entails assigning an installed capacity obligation to each member and requiring a member to make an installed capacity deficiency payment when its available capacity falls below its obligation. To avoid such a payment, a member can also purchase installed capacity credits from other member companies who have available capacity above their installed capacity obligation.

PJM also establishes reserve requirements necessary to meet the reliability standard for the pool. These reserve requirements are the basis for, but from time to time have differed from, the installed capacity obligation used for pool accounting purposes.

Q. What is the basis for the PJM reserve requirement?

A. PJM measures reliability by the one-day-in-ten-years loss of load probability standard. As its name suggests, this standard defines the requisite level of reserves needed to assure that, on a probabilistic basis, demand will exceed available capacity on average only one day out of every ten years. The one-day-in-ten-years standard is a well-accepted measure of minimum system reliability and is the standard adopted by MAAC.

Q. What reserve requirement is needed by PJM overall to meet the one-day-in-ten-years standard?

A. Giving consideration to such factors as PJM's load characteristics, unit forced outage rates, unit maintenance requirements and transmission ties with neighboring power systems, a minimum reserve requirement of 22 percent is currently necessary for PJM to meet its stated reliability standard. This figure will decrease to 21.5% in June 1995 and 21.0% in June 1996.

Q. How does PJM determine each member's responsibility for providing resources necessary to meet the pool's 22 percent reserve margin requirement?

A. Responsibility for maintaining the 22 percent minimum reserve requirement is allocated to PJM's members based on their adjusted peaks over a defined planning period, which reflects, among other things, the timing of each member's peak relative to the pool's peak. Other factors affecting the allocation include members' load shapes, maintenance requirements and forced outage rates. Based on this allocation, PP&L is currently obligated to have resources that, expressed in terms of PP&L's winter peak, provide an approximately 12 percent reserve margin.

The principal reason that PP&L's obligation is below the 22 percent minimum reserve margin for PJM overall is PP&L's peak load diversity relative to the pool. PP&L is a winter-peaking utility, while PJM experiences its overall peak in the summer. If PP&L were not a member of PJM, its minimum reserve requirement, on a stand-alone basis, would be substantially above 22 percent.

Q. **Mr. Sipics, if 12 percent establishes the low end of the appropriate reserve margin range, what factors should be considered in assessing the upper end of the range?**

A. In assessing the upper limits of the range, consideration must be given to the practical aspects of capacity planning. Capacity cannot be added (or subtracted) megawatt by megawatt to match the changing demands of customers. This "lumpiness" of capacity will cause reserve margins to increase when capacity is added and then shrink over time as customer demand grows.

Additionally, practicality dictates that a utility recognize the limitations inherent in the projections that go into predicting future reserve margins. Peak demand is the most obvious example of a variable that could differ materially from forecasted levels. Also, the level of control the utility has over its planned resources affects the appropriate reserve level. In PP&L's case, interruptible service contracts are renewable annually. Changes in customers' cost structures or industrial processes, to cite only two examples, could cause existing interruptible service customers to seek the higher reliability of firm service. In the same vein, non-utility generators may not renew their agreements to sell output to PP&L when those agreements expire. Additionally, non-utility generators pose the risk of non-performance during the term of their existing contracts due to financial failure or other conditions of default.

Other, less obvious variables could also have a significant impact, such as projections of the performance of generating equipment. This was dramatically illustrated by events of January 1994 when several power disruptions affected PJM despite earlier forecasts of an ample reserve margin for the winter of 1993-1994. As events transpired, although planned maintenance levels were typical, there was unusually high unit unavailability due to a variety of ice and cold weather problems, such as impaired fuel delivery and fuel handling and plant component failures. As shown on Exhibit JFS-2, the occurrence of 16,100 megawatts of forced outages for PJM, as compared to a forecasted level of 6,200 megawatts, was a major contributor to the lack of adequate reserves.

The events of January 1994 underscored one of the disadvantages for PP&L of being a winter-peaking company. Unpredictable changes in weather patterns can drive peak demands up at the same time weather-related problems are forcing the unavailability of generating equipment. The effect of adverse weather on fuel handling and delivery is particularly acute for a utility such as PP&L that has over 4,000 megawatts of coal-fired generating capacity.

Q. Returning to Exhibit JFS-1, in light of your discussion of reserve margins, please identify the data that are most appropriate for assessing PP&L's reserve margins in the context of a rate proceeding.

A. The most appropriate data for assessing PP&L's reserve margins in the context of this rate proceeding are those reflected in the column captioned "Reserves At The Time Of The Peak [With Interruptible Load]." As I earlier explained, these reserve margins are based on PP&L's owned and leased generation and the load likely to be available for interruption at the time of PP&L's peak. In contrast to the addition of non-utility generation, PP&L exercised control, in the case of owned and leased generation, or partial control, in the case of interruptible load, over the acquisition of these resources. PP&L exercised <u>partial</u> control over the acquisition of interruptible load because, while the decision to offer interruptible service was made by PP&L, the extent of interruptible load that was added was a function of customer response, which generally exceeded PP&L's prior projections.

Q. Please explain why PP&L was not able to exercise control over the addition of non-utility generation.

A. In an effort to encourage the development of co-generators and small power producers, federal law requires electric utilities such as PP&L to purchase power from non-utility generators that satisfy the conditions necessary to become "qualifying facilities" under Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Accordingly, PP&L was required to enter into agreements to purchase power from these non-utility generators without regard to its existing or projected peak loads or reserve margins. Virtually all of the agreements with non-utility generators were executed after PP&L's last capacity addition was substantially completed.

Q. Why is non-utility generation shown as a resource on Exhibit JFS-1?

A. Earlier, in discussing the operation of PJM, I explained that PJM imposes an installed capacity obligation on each member as part of its accounting procedures. As part of these procedures, PJM allows member companies to meet their installed capacity obligation based on non-utility generation that has exhibited a reasonably consistent level of operation over an historical period.

Q. Are the reductions in PP&L's resources resulting from installed capacity credit sales also a function of PJM accounting procedures?

A. Yes, PP&L's capacity credit sales represent a reduction in the seller's resources and an increase in the purchaser's resources for installed capacity accounting purposes only. No physical capacity exchange occurs.

Q. Please summarize your conclusions regarding PP&L's reserve margins.

A. An appropriate reserve margin lies within a range, and is not a single figure. For PP&L, the lower end of the reserve margin range is its allocated portion of PJM's overall reserve requirement, which is determined over a defined planning period and, expressed as a function of winter peak load, is approximately 12 percent. In assessing the upper end of the range, which is more difficult to quantify, consideration must be given to various factors including the impracticality of adding generating capacity in small, discrete units; the inherent limitations of forecasted data; the level of control over non-utility resources; and the added concern about unit performance in winter months for a winter-peaking utility. In addition, in PP&L's last base rate case the Commission accepted the Trial Staff's analysis which found that a reserve margin of slightly over 22% was reasonable. For purposes of this rate proceeding, PP&L's reserve margins are most appropriately assessed on the basis of its owned and leased generation and available interruptible load, which reflect reserve margins ranging from a low of 14.2 percent (1995-1996) to a high of 19.6 percent (2000-2001). These reserve margins are clearly within a range of reasonable reserve margins for PP&L in view of the factors I described earlier.

Q. You previously explained that interruptible load provides a capacity equivalent resource. To what kind of generating resource is interruptible load most comparable?

A. Viewed as a capacity equivalent resource, interruptible load is most comparable to peaking capacity because it can be targeted, within practical limitations, to periods when peak demands are likely to occur. However, its peak reduction capability is available for only a limited number of occurrences of limited duration. The frequency and duration limitations are a function of the tariff and contract provisions necessary to create reasonable incentives for customers to accept non-firm service. Price reduction alone would be unlikely to encourage industrial customers to accept non-firm service if they were subject to an unlimited number of interruptions of unlimited duration.

While interruptible load is, in general, comparable to peaking capacity, it can be less desirable than peaking-type generating units, such as quick-start combustion turbines, because it is not directly controlled by the utility (the customer may not interrupt when asked to do so) and requires more lead time to initiate (interruptible customers typically require advance notice of an interruption -- one to two hours under current interruptible service agreements -- to stop or modify their industrial processes).

Q. In view of the factors you outlined above, what is the appropriate basis for determining the value to PP&L or, alternatively, the effect on PP&L's cost structure, of having interruptible load?

A. The value to PP&L of having interruptible load, as well as the effect of such interruptible load on PP&L's cost structure, which I regard as one in the same, are properly determined by reference to the annual carrying cost of a combustion turbine peaking unit. A recent analysis prepared by PP&L indicates that developments in the production and marketing of combustion turbines have been such that capacity of that type can be installed at a cost of about $300 per kilowatt (kW), with a resulting carrying cost of about $45/kW-year.

Q. Earlier you explained that PJM requires each member to meet an installed capacity obligation and requires installed capacity deficiency payments if that obligation is not met. Does interruptible load count as installed capacity for PJM accounting purposes?

A. Yes, it does. The available interruptible load of PJM members, calculated in the manner I earlier described, is used to meet their installed capacity obligations to PJM.

Q. How would the value and/or effect on PP&L's cost structure of interruptible load differ if measured by reference to its value in meeting the installed capacity obligation on PJM?

A. Currently, the PJM payment rate, if a member experiences an installed capacity deficiency, is $73/kW-year. However, that figure is based on the annual carrying cost of a combustion turbine as calculated by PJM approximately one year ago using historical data. As more recent data are incorporated in that calculation, the deficiency payment rate will decline. Nonetheless, the PJM deficiency payment rate is not the proper measure of the value of installed capacity credits, because those credits are actively traded based on current market prices that are well below the PJM payment rate.

As I explained before, a PJM member would not incur a PJM deficiency payment if it could purchase installed capacity credits at a lower price from another member that has capacity credits available for sale. Recent market transactions indicate that installed capacity credits have been purchased and sold for as low as 15% to 20% of the PJM deficiency payment rate. These discounts will likely decline over time as loads and capacity on PJM become more closely aligned, and the value of installed capacity will move closer to the PJM installed capacity deficiency rate.

Q. What is shown by Attachment I-B-3?

A. Attachment I-B-3 contains a map of the PP&L electric system. The map is a detailed electric system diagram. It shows the arrangement of all PP&L generating and transmission facilities, 69 kV and above. It is representative of the system at December 31, 1993.

Q. Does this conclude your direct testimony?

A. Yes.

PENNSYLVANIA POWER & LIGHT COMPANY

LOAD AND CAPACITY FORECAST 1994-2003

Winter Capacity & Loads

Winter Peak Load Period	Winter Peak Load (MW)	PP&L Owned or Leased Capacity (MW) (1)	Capacity Additions and Reductions: Location (MW)	Capacity Additions and Reductions: Inservice Date	Firm Capacity Sales to Other Utilities (MW): AE (MW) (4)	Firm Capacity Sales to Other Utilities (MW): BG&E (MW) (5)	Firm Capacity Sales to Other Utilities (MW): JCP&L (MW) (6)	Net Resources At Time Of Peak w/o NUG, IL, & CC Sales (MW)	Reserves At The Time Of the Peak w/o NUG, IL, & CC Sales (MW)	Reserves At The Time Of the Peak w/o NUG, IL, & CC Sales (%)	Interruptible Load Adjustment (MW) (7)	Reserves At The Time Of the Peak w/ IL (MW)	Reserves At The Time Of the Peak w/ IL (%)	NUG (MW)	Reserves At The Time Of the Peak w/ IL & NUG (MW)	Reserves At The Time Of the Peak w/ IL & NUG (%)	Capacity Credit Sales to Other PJM Utilities (MW): GPU (MW) (4)	Capacity Credit Sales to Other PJM Utilities (MW): BG&E (MW) (5)	Capacity Credit Sales to Other PJM Utilities (MW): PEP (MW) (6)	Reserves At The Time Of the Peak w/ IL, NUG, & CC Sales (MW)	Reserves At The Time Of the Peak w/ IL, NUG, & CC Sales (%)
94/95	6605	8543			-129	-129	-945	7340	735	11.1%	345	1080	16.4%	504	1584	24.0%	-390	-50	-147	997	15.1%
95/96	6725	8540	Derate MC 3 & 4 (-13 & -35 MW) (8)	1/1/95	-129	-132	-945	7334	609	9.1%	345	954	14.2%	474	1428	21.2%		-183		1245	18.5%
			Susquehanna 1 Uprate (45MW) (2)	6/1/95																	
96/97	6790	8540			-129	-132	-756	7523	733	10.8%	345	1078	15.9%	474	1552	22.9%				1552	22.9%
97/98	6915	8588	Uprate MC 3 & 4 (13 & 35 MW) (8)	6/97	-129	-132	-567	7760	845	12.2%	345	1190	17.2%	474	1664	24.1%				1664	24.1%
98/99	7050	8588			-129	-132	-378	7949	899	12.8%	345	1244	17.6%	474	1718	24.4%				1718	24.4%
99/00	7185	8570	Montour 1 Scrubber (-18 MW) (3)	6/1/99	-129	-132	-189	8120	935	13.0%	345	1280	17.8%	474	1754	24.4%				1754	24.4%
00/01	7330	8552	Montour 2 Scrubber (-18 MW) (3)	6/1/00		-132		8420	1090	14.9%	345	1435	19.6%	474	1909	26.0%				1909	26.0%
01/02	7465	8552						8552	1087	14.6%	345	1432	19.2%	474	1906	25.5%				1906	25.5%
02/03	7600	8552						8552	952	12.5%	345	1297	17.1%	474	1771	23.3%				1771	23.3%
03/04	7745	8552						8552	807	10.4%	345	1152	14.9%	474	1626	21.0%				1626	21.0%

Notes:

(1) Winter capacity of PP&L's wholly owned, and share of joint owned units as of December 1st of the Winter Period.

(2) Includes only PP&L's 90% share of the 50 MW uprate in Susquehanna SES Unit 1. Allegheny Electric Cooperative owns the remaining 10 % (5 MW of the uprate).

(3) Capacity decreases resulting from the addition of scrubbers to meet the requirements of the 1990 Clean Air Act.

(4) Reflects agreements for Atlantic Electric Co. (AE) to purchase 125MW (Summer Capacity) of PP&L's wholly owned coal fired capacity and energy from 10/1/91 to 9/30/00.

(5) Reflects agreements for Baltimore Gas & Electric Co. (BG&E) to purchase 6.6% of PP&L's share of Susquehanna capacity and energy from 10/1/91 to 5/31/01.

(6) Reflects agreements for Jersey Central Power & Light Co. (JCP&L) to purchase 945 MW (Winter Capacity) of PP&L's average system capacity and energy.
This purchase is proportionately reduced beginning in 1/1/96 and terminated in 1/1/00.

(7) The value of PP&L's Interruptible Load is based on PP&L's estimate of the average availability of the interruptible load at the time of each of PP&L's 13 summer weekly peaks.
The value is currently estimated to be 290 MW. This value is converted into an equivalent capacity value based on the procedures outlined in the PJM Active Load Management Report.
The values shown above are PP&L's estimate of the capacity value of this interruptible load.

(8) Derate of Martins Creek 3 & 4 by 13 and 35 MW respectively for damaged turbine blades. Repairs are expected to be completed in the Spring of 1997.

Exhibit JFS-1

1993-94 Winter Forecast Conditions vs. Actual Conditions

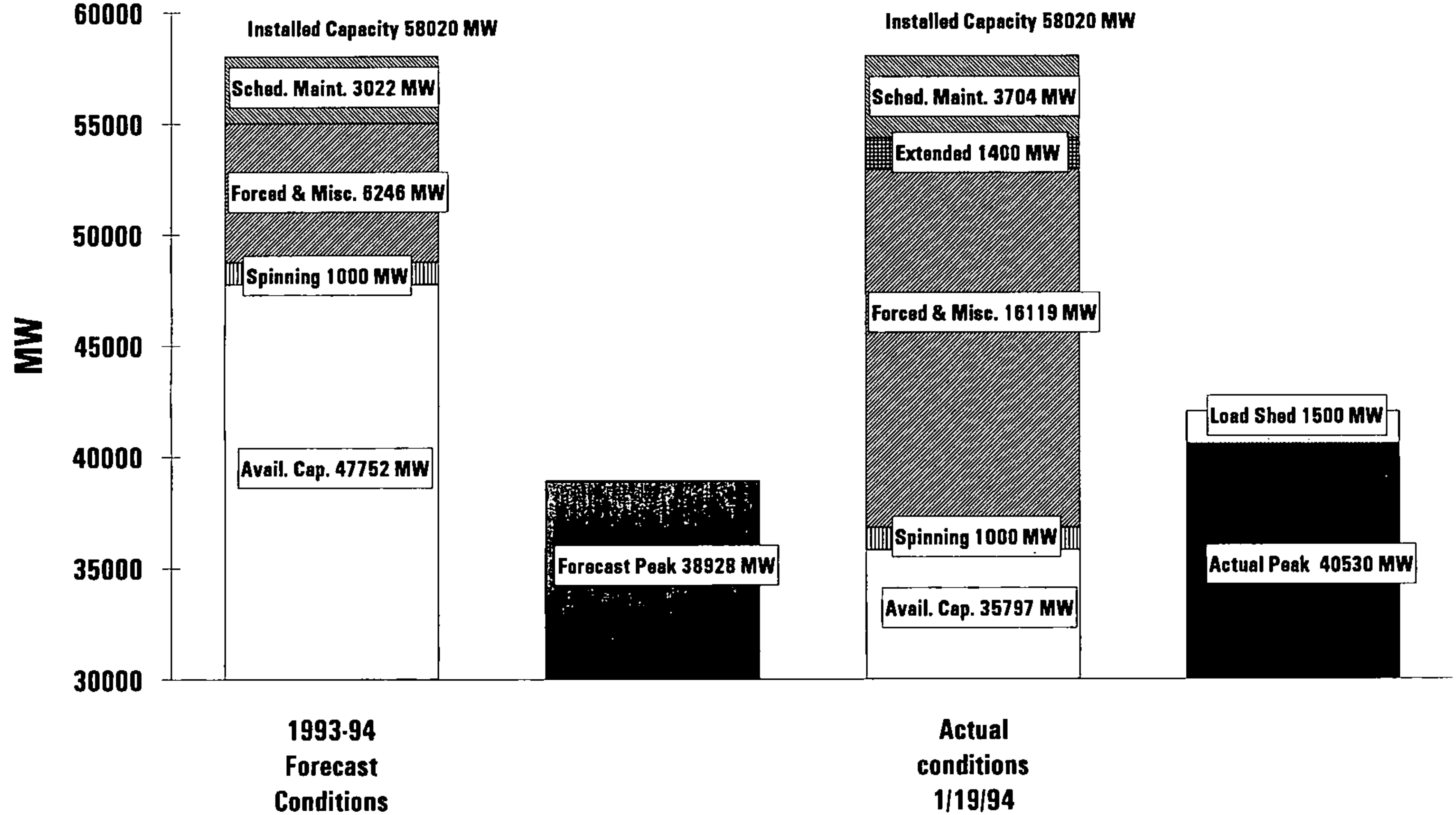


Exhibit JFS-2