BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, et al.	:	Docket Number
v.	:	R-822169, et al.
Pennsylvania Power & Light Company	:	

RECOMMENDED DECISION
of
ADMINISTRATIVE LAW JUDGE
JOSEPH J. KLOVEKORN

DOCKETED
JUL 6 1983

APPEARANCES:

Robert H. Young, Esq.
Thomas P. Gadsden, Esq.
David B. MacGregor, Esq.
Morgan, Lewis & Bockius
2100 The Fidelity Building
123 South Broad Street
Philadelphia, PA 19109
for: Pennsylvania Power & Light Company

DOCUMENT
FOLDER

G. D. Caliendo, Esq.
Paul E. Russell, Esq.
Pennsylvania Power & Light Company
Two North Ninth Street
Allentown, PA 18101
for: Pennsylvania Power & Light Company

Philip F. McClelland, Esq.
Irwin A. Popowsky, Esq.
David M. Barasch, Esq.
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120
for: Office of Consumer Advocate

Frank B. Wilmarth, Esq.
John M. Quain, Esq.
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17120
for: Commission Prosecutory Trial Staff

APPEARANCES (continued):

J. Jackson Eaton, III, Esq.
Thomas C. Sadler, Esq.
Butz, Hudders & Tallman
740 Hamilton Mall
Allentown, PA 18101
for: Eastern Penn Energy Association

D. Jane Drennan, Esq.
Norma J. Rosner, Esq.
Pillsbury, Madison & Sutro
1050 17th Street, N.W.
Washington, D.C. 20036
for: Pennsylvania Industrial Coalition

Henry R. MacNicholas, Esq.
McNees, Wallace & Nurick
100 Pine Street
P.O. Box 1166
Harrisburg, PA 17108
for: Lehigh Valley Power Committee

Bernard A. Ryan, Jr., Esq.
Cheryl Ussery, Esq.
Dechert Price & Rhoads
800 North Third Street
Harrisburg, PA 17102
for: Bethlehem Steel Corporation

Otto F. Hofmann, Esq.
213-A North Front Street
Harrisburg, PA 17101
for: Pennsylvania Utility Law Project

David Mann
P.O. Box 249
Lewisburg, PA 17837
for: Susquehanna Alliance

Larry B. Selkowitz, Esq.
Mark P. Widoff, Esq.
Widoff, Reager, Selkowitz & Adler, P.C.
1104 Fernwood Avenue
Camp Hill, PA 17011
for: City of Harrisburg

Peggy Wells Dobbins, Esq.
St. Regis Corporation
237 Park Avenue
New York, New York 10017
for: St. Regis Corporation

APPEARANCES (Continued):

David A. McCormick, Esq.
Delton E. Coker, Esq.
U.S. Army Legal Services Agency
JALS-RL 3128
5611 Columbia Pike
Falls Church, VA 22041
for: U..S. Department of Defense

Charles B. Zwally, Esq.
Shearer, Mette & Woodside
1801 North Front Street
P.O. Box 729
Harrisburg, PA 17108
for: Milton Manufacturing Company
Crown American Corporation
Hess's Department Stores, Inc.

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I. INTRODUCTION

On November 22, 1982, Pennsylvania Power & Light Company (PP&L) filed Supplement No. 2 to Tariff Electric - Pa. P.U.C. No. 199, to become effective January 22, 1983. This Supplement contained proposed changes in rates, rules and regulations calculated to produce an approximate net increase of $315,000,000 in additional annual revenues, based upon the projected level of operations in the twelve months ended July 31, 1983. The filing includes as a revenue offset a projected $186,000,000 estimated savings in energy costs applicable to PP&L's Susquehanna Steam Electric Station Unit No. 1 (Susquehanna) which went into commercial operation on June 8, 1983. This projection is based on the lower cost of nuclear fuel compared with coal or oil, and upon projected sales of power to other utilities. Due to the projected increase in energy cost savings, the net revenue increase is projected to be approximately $315,000,000, after giving effect to projected energy savings of $186,000,000.

On December 3, 1982, the proposed increase was suspended by operation of law until August 22, 1983. At that time the Commission instituted this investigation to determine the reasonableness of the proposed tariff supplement.

On February 8, 1983, the undersigned Administrative Law Judge was assigned to preside at this investigation. Some 22 formal evidentiary hearings and 12 public input hearings were held in Harrisburg, Allentown, Scranton, Bloomsburg, Williamsport, Wilkes-Barre, Hazleton, Lewisburg, Sunbury, Lancaster, Pottsville and Stroudsburg. Approximately 180 formal complaints have been filed against this increase. Briefs and reply briefs have been received from PP&L, the Office of Consumer Advocate (OCA), the Commission's Prosecutory Trial Staff (Trial Staff), the Eastern Penn Energy Association

(EPEA),[1] St. Regis Corporation, Pennsylvania Industrial Coalition (PIC),[2] Lehigh Valley Power Committee (LVPC),[3] Bethlehem Steel Corporation, Pennsylvania Public Utility Law Project, Susquehanna Alliance, the city of Harrisburg, the United States Department of Defense, Milton Manufacturing Company, Crown American Corporation and Hess Department Stores, Inc.

After reviewing the testimony and exhibits contained in the record of this proceeding, I recommend that the Commission permit PP&L to file revised tariffs designed to produce some $201,652,000 in additional annual revenue. This amount is the lowest reasonable amount which can be supported on the record consistent with the provision of safe and adequate service.

II. THE COMPANY

Pennsylvania Power & Light Company was founded in 1920 through the consolidation of eight electric companies. On March 1, 1980, the former Hershey Electric Company was merged into PP&L. PP&L presently serves a 10,000

1/ EPEA is a group of medium-sized industrial and commercial customers of PP&L. The following members have intervened in this proceeding: Modern Slack Creations, Inc., Penn Linen & Uniform Services, Atlantic Processing, Inc., General Machine Co., The Greif Companies, Ross Bicycles, Inc., Rodale Press, Burron Medical Inc., L.V. Refrigeration Services and Lackawanna Cold Storage and Boise Cascade.

2/ PIC consists of several large industrial customers of PP&L who take service under either the utility's LP-5 or LP-6 rate schedules.

3/ LVPC consists of the following large industrial and commercial customers: Airco, Inc., Coplay Cement Company, Gulf & Western Industries, Hercules Cement Company, Keystone Portland Cement Company, Lone Star Industries, Inc., the New Jersey Zinc Company, the Whitehall Cement Manufacturing Company. Recent members with new facilities due "on stream" in the next several months include Air Products and Chemicals, Inc. and Union Carbide Corporation.

square mile territory which encompasses 29 counties in central-eastern Pennsylvania. This territory has a population of approximately 2,400,000 and contains extensive agricultural and industrial regions, as well as over 800 major communities (PP&L Exhibit Regs. I-A-1). During the twelve months ended July 31, 1983, PP&L estimates that it will serve 1,014,697 jurisdictional customers (PP&L Exhibit Regs. §53.52(a)).

In addition to its retail operations, the company supplies wholesale electric service to 14 Pennsylvania boroughs. It also provides electric service to the Luzerne Electric Division of UGI Corporation under a firm power supply agreement, and provides short term interruptible energy to several utilities in New York and New England. These wholesale services are subject to the regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC).

As noted earlier, the company is currently in the process of completing construction of the Susquehanna Steam Electric Station, a two unit nuclear power plant located near Berwick, Pennsylvania. Each generating unit has a maximum design capacity of 1050 megawatts (PP&L St. 11, p.3). A 10% undivided share of each unit is owned by Allegheny Electric Cooperative, Inc., which is entitled to a pro rata portion of the plant's output (PP&L St. 11, p.4). In addition, Atlantic City Electric Company has purchased 6.6% of the company's share of the capacity and related energy from the Susquehanna units for a term commencing with the commercial operation date of each unit and ending in September 1991 (PP&L St. 11, p.4). PP&L received an operating license for Susquehanna Unit 1 from the Nuclear Regulatory Commission in July 1982. Commercial operation of Unit 1 began on June 8, 1983; commercial operation of Unit 2 is scheduled to begin in the fourth quarter of 1984.

The company also owns and operates five steam and two hydro-electric generating stations, as well as a number of combustion turbine and diesel units located throughout its system (PP&L St. 11, p.3). Additionally, the company is entitled to 12.34% of the output of the Keystone Station and 11.39% of the Conemaugh Station, two mine-mouth plants which it jointly owns with other companies (PP&L St. 11, p.3). The company's generating capability also includes the purchase of 76,000 kw from the hydro-electric plant of Safe Harbor Water Power Corporation, one-third of the common stock of which is owned by PP&L. The company's total generating capability at July 31, 1982 was 6546 mw (PP&L St. 11, p.3).

The system consists of an integrated power transmission system with 1,084 miles of transmission line operating at 230,000 volts or higher, more than 280 substations of a capacity of 10,000 kva and over, and approximately 49,000 miles of distribution line operating at less than 230,000 volts (PP&L St. 11, p.4).

The company operates its generation and transmission facilities as a part of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection (PP&L St. 12, p.4). The transmission facilities provide the electrical links between the PP&L system and the systems of its neighboring companies. The PJM Interconnection consists of 11 electric utility systems in the states of Pennsylvania, New Jersey, Maryland, Delaware, Virginia and the District of Columbia (PP&L St. 12, p.4). These member utilities coordinate the operation of their generating capability and bulk power transmission systems so that the combined load of all the systems is carried in the most economic manner consistent with established constraints of reliability (PP&L St. 12, p. 4). This operation is governed by the PJM Interconnection Agreement, a rate schedule subject to the jurisdiction of FERC (PP&L St. 12, p. 4).

III. PUBLIC INPUT HEARINGS

As noted earlier, some twelve public input hearings were held in the PP&L service territory for the purpose of permitting the company's ratepayers an opportunity to participate in this proceeding.

Although the number of hearings held has been criticized as "unnecessary" (PP&L M.B.I., p. 131), due to the company's widespread service area, more than the usual number of public input meetings were required. These hearings would serve no purpose if public participation were inhibited by Commission-imposed obstacles. Certainly, no ratepayer should be forced to travel an extensive distance in order to testify on a matter which so affects his daily life as his utility bill.

Approximately 275 statements were entered into the record; on a few occasions ratepayers testified more than once. Attendance at these hearings ranged from approximately 30 persons to approximately one thousand. The concerns expressed by these ratepayers fall into two general categories: (1) the adverse economic impact of the rate increase, especially on the depressed industries of the area and on the unemployed and aged; and (2) the need for and cost of the Susquehanna Steam Electric Station (SSES). This latter subject will be dealt with extensively in consideration of adjustments proposed by the OCA, Trial Staff and several industrial intervenors. It is the former - the economic impact of this rate increase which will be considered at this time.

Throughout these non-evidentiary hearings, witnesses have requested that the company include an economic impact statement in its rate filing or that the Commission include such a statement in its decision.

At the public input hearing in Lewisburg, several ratepayers presented such a statement which was responded to by the company. These witnesses[4] are to be commended for their interest and diligence in preparing this document.

Due to the complexity of the relationships between the types of data which could measure economic impact in a rate case, as demonstrated by the document presented in Lewisburg and the company's response thereto (PP&L St. PIR-4), it does not appear practical or possible to construct a formulary approach to this issue, such as many witnesses have suggested.

It would appear that the consequences of rate determinations, for the economic circumstances of a utility's territory, are better set forth through the evidence offered by parties both in public input hearings and in formal evidentiary hearings than in any specific study.

Economic impact connotes more than the difficulty or hardship imposed on a consumer by an increase in his monthly utility bills. Utility rates have various potentially harmful and beneficial multiplier effects on the overall financial and economic health of a service area. Certainly testimony bringing out these effects, by demonstrating the connection among classes of customers, the socio-economic environment, and the proposed rates, could and should influence this Commission's determination of various elements of the ultimate rate decision in this proceeding.

This Commission has implicitly recognized in its rate decisions the economic impact of rate increases. First, it should never be forgotten that concern about potential customer hardship is central to the very concept of utility regulation. Statute and case law require the Commission to examine proposed rates to assure that they do not exceed the minimum that will cover a

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4/ Steve Stamos, Adrienne Lyon and Charles Sackrey company's prudently incurred costs, including a reasonable return allowance. Regulation in the public interest assures that prices will be just and reasonable, and not the maximum that a company might exact by reason of its monopoly position. While the Commission cannot legally set revenues lower than the company's legitimate cost of service, certain portions of the rate equation present opportunities to consider economic impact. Indeed, the Commission has taken such opportunities routinely in rate cases decided in recent years. For example, in setting an expense allowance within a range of reasonableness, the Commission often chooses the lower end of the range; in determining when to begin making a necessary provision, such as an allowance for amortization, it has often decided to postpone the effective date of the provision or to amortize it over a longer period of time than that proposed by the utility; and, in deciding how to alter rate designs, it has considered the specific impact on various groups of customers.

These decisions stem directly from our statutory responsibility to assure safe and adequate service at just and reasonable rates. For that purpose, it may make sense to moderate a rate increase in the ways described above where, for example, there is persuasive testimony that higher rates, at a time of economic distress, would adversely affect the public -- including the utility company -- by precipitating or aggravating economic dislocations and problems such as unemployment, dependence on public assistance, and departure of industries from the service territory.

In summary, the regulatory scheme envisioned by the General Assembly of this Commonwealth requires this Commission to be sensitive to the impact of rates on the general economy. This proceeding is no exception and, to this end, the public input hearings presented the opportunity for relevant testimony on this subject to be introduced in the record here.

IV. RATE BASE

PP&L's claimed measure of value in this proceeding is equivalent to the depreciated original cost of its electric plant in service at July 31, 1983, plus investments in electric plant held for future use, pollution control projects under construction and working capital.

The undepreciated original cost of the company's electric plant in service at the end of the historic test year was taken directly from PP&L's continuing property records (PP&L Exhibit Historic 1, C-1; PP&L St. 2, p. 15). The original cost values recorded on the company's books of account were originally approved by the Commission in the 1940's and have since been maintained in conformity with the Commission's regulations and with the Uniform System of Accounts for Class A electric companies prescribed by the Federal Energy Regulatory Commission (FERC). The account balances are audited periodically by both FERC and the Commission Staff and are audited on an annual basis by a firm of independent certified public accountants.

The orignal cost values at future test year end were developed by taking the actual book balances at July 31, 1982 and factoring in those plant additions and retirements anticipated to occur during the twelve months ending July 31, 1983. The projected additions and retirements were derived from the company's 1982-1983 Construction Budget (PP&L Exhibit WFH 1), as adjusted for ratemaking purposes to reflect the most recent available information (PP&L Exhibit WFH 2). Mr. William F. Hecht, PP&L's Manager-System Planning, testified to the process of budgeting plant additions and retirements which provided the basis for the company's estimate of the original cost of electric plant in service at July 31, 1983 (PP&L St. 11, pp. 6-12).

As noted previously, the company provides electric service to a number of municipalities and other utilities at wholesale rates established by

FERC. Accordingly, for the purposes of this proceeding, it was necessary to identify and eliminate from each component of the claimed measure of value that portion devoted to providing non-jurisdictional service. The allocated amounts were derived by Mr. Andrew J. Baldwin, Assistant Vice-President - Division Operations for the company, as part of a cost allocation study which he prepared for this case (PP&L Exhibit AJB 3). The allocations have not been challenged. After the appropriate allocation to wholesale operations, the company's claim for original cost of plant in service at July 31, 1983 equals $4,338,888,000 (PP&L Exhibit Future 1, C-1, p.2).

The various issues raised with respect to rate base, revenues and expenses and depreciation can be separated into Susquehanna Steam Electric Station - related areas and non-SSES areas. For the convenience of the Commission and the parties, these two areas will be considered separately.

A. NON-SUSQUEHANNA ISSUES

The issues raised by the parties concerning non-Susquehanna related items in rate base are relatively few. Each will be considered separately.

1. Electric Plant Held for Future Use

The company's original cost measure of value includes a claim of $11,819,000, representing PP&L's investment in land for the expansion of existing or the location of future production, transmission and distribution facilities and general plant (PP&L Exhibit Future 1, C-1, p.2). According to the company, all of the sites for which rate base treatment is sought were acquired pursuant to and are held under a definite plan for their use in the company's future electric operations (PP&L St. 11, p.16).

As explained by PP&L witness Hecht, there are several reasons why the company must obtain these property interests well in advance of their actual use. First, it can no longer be assumed that such sites will be readily available when required to service the needs of future customers. In recent years, any number of factors, including the increased usage of waterfront properties for recreational and residential purposes, as well as mounting environmental concerns, have severely diminished the land which may be utilized for electric utility purposes. The company claims that land has become a scarce commodity and it would be imprudent for the company to ignore that fact.

The company also argues that land continues to skyrocket in cost and that even if adequate sites prove to be available ten or twenty years from now, they will be obtainable only at greatly inflated prices. Accordingly, any delay in their acquisition will impose an unnecessary burden on future ratepayers. Finally, PP&L argues, there is invariably a substantial lag between the commencement of design and construction of electric supply facilities and the eventual licensing of those facilities for in-service use. A utility must complete the site acquisition process well in advance of that period.

Trial Staff witness Michael Gruber noted that seven of the properties claimed by PP&L have expected in-service dates of more than 10 years beyond the end of the July 31, 1983 test year. The actual range for projected use of the seven properties is from 18 to 26 years beyond the end of the future test year (Staff Exhibit 4-A, p.2).

Trial Staff argues that projections of 18 years and longer beyond the end of a future test year are speculative. In addition, Trial Staff argues that the Commission has consistently used 10 years as a reasonable cut-off point for the inclusion of electric utility plant held for future use in rate base. Pennsylvania Power & Light Co., 54 Pa. P.U.C. 645, 649 (1981).

The company claims that ten years no longer realistically measures the time required by an electric utility to plan and provide for the future needs of its customers. As such, it argues, the rigid application of this standard will force PP&L either to continue to absorb the carrying costs associated with these parcels or to dispose of valuable utility property which may never become available again. It calls upon the Commission to re-examine this standard.

The Commission's policy is to allow the inclusion of land held for future use in rate base (1) when definite plans are available and (2) such utilization will occur within a reasonable time. The Commission has established 10 years as a reasonable time. Pennsylvania Electric Co. (R.I.D. 172, 1976)

Here, the properties involved have been acquired and included in this account during the period 1969-1977. They are not expected to be used until 1994-2000. Under these circumstances, even if the Commission were to consider a period in excess of 10 years to be reasonable, substantial portions of the disputed claim should fail for lack of a definite plan. In-service dates stretching to the end of this century lack the definiteness needed for this item. The company's jurisdictional claim should be reduced by $751,135.

OCA witness Cotton recommended that the company's entire claim for electric plant held for future use be disallowed (OCA St. No. 5, pp. 10-12). The basis for this recommendation is that plant held for future use is conceptually the same as construction work in progress (CWIP).

The OCA recognizes that the Commission considered and rejected a similar argument in PP&L's last litigated rate case (R-80031114, 54 Pa. P.U.C. 645). There the Commission stated (p. 649):

> Further, we do not subscribe to the OCA's analogy between plant held for future use and CWIP. Pursuant to the Uniform System of Accounts, approved by us, the cost of land purchased for use in the future is included in Account 105 (electric plant held for future use). We do not find any provision within the Uniform System of Accounts either requiring or permitting the inclusion of the cost of land within Account 107 during construction of improvements on the land (construction work in progress -- electric), rather, this cost should remain in Account 105 until closed to a plant-in-service land account when the facility constructed upon it is placed in service. In contrast, the CWIP account is normally limited to expenditures for improvements constructed on the property. Although construction on the land must be booked to the CWIP account, the cost of the land itself remains in Account 105 until completion of the project. Therefore, we reject the consumer advocate's analogy. (Footnote omitted.)

The OCA argues, however, that recent amendments to the Public Utility Code have changed this situation (OCA M.B. pp. 98-100). Under Act 335, P.L. 1473 (December 30, 1982), the inclusion of CWIP in rate base was precluded.

The argument was recently rejected by the Commission in Duquesne Light Co. (R-821945, Order on Reconsideration, issued April 18, 1983). There the Commission rejected the OCA's interpretation of Act 335 and concluded that the legislation was designed to serve a limited purpose:

> . . . we are led to the conclusion that the legislature did not intend that the Act be interpreted in the manner urged by the OCA but rather it was an endorsement of past Commission regulatory treatment of construction work in progress and a prescription of the continuation of that practice. (Order, p. 10)

The OCA adjustment should be rejected.

2. Pollution Control Projects Under Construction

The company has included in its claimed original cost measure of value $2,572,000, representing its investment through the end of the future test year in pollution control equipment currently being installed at the Sunbury and Montour generating plants (PP&L Exhibit Future 1, C-1, p. 2 and C-4, p. 1).

As explained by PP&L witness Hecht (PP&L St. 11, pp. 13-14), the work being performed is required to meet the Pennsylvania Department of Environmental Resources' water pollution regulations. The construction of these facilities, which is scheduled to be completed in 1984, will neither expand the plants' generating capabilities nor enable the company to reduce expenses or generate additional revenues. Rather, the installation of this equipment is required solely to maintain existing plant in its present used and useful status and, as such, fully comports with Act 335 and the Commission's criteria for inclusion of CWIP in rate base. Philadelphia Electric Co., 55 Pa. P.U.C. 78 (1981), Pennsylvania Power & Light Co., 54 Pa. P.U.C. 645 (1981).

PP&L's claim has not been challenged here. In view of the compulsory and non-revenue producing nature of this investment and the benefits derived by current customers by virtue of the continued operations of these facilities, PP&L's rate base request for Pollution Control Projects Under Construction is reasonable and should be approved.

3. Working Capital

The company's claim for working capital equals $219,637,000 and consists of the following elements: (a) cash needs attributable to operating and maintenance expenses, average prepayments and accrued taxes of $26,039,000 and (b) fuel inventory, materials and supplies and undistributed stores expense totalling $193,598,000 (PP&L Ex. Future 1, C-1, p. 2).

a. Cash Working Capital Requirements

The necessity for a working capital allowance as a rate base addition was described by the Pennsylvania Supreme Court in Pittsburgh v. Pa. P.U.C., 370 Pa. 305, 88 A.2d 59 (1952), as follows:

> Cash working capital ordinarily is the amount of cash required to operate a utility during the interim between the rendition of service and the receipt of payment therefore (sic). It is the bloodstream that gives life to the physical plant and facilities of the enterprise. It can readily be seen that, initially, at the commencement of operation, capital supplied by investors must, in order for the company to function, include such working cash in addition to the amount required for physical plant and facilities. Its allowance as an element of fair value for ratemaking purposes has been approved by decisions of both the Superior and Supreme Courts of this State and of the appellate courts of other jurisdictions. (370 Pa. at 309)

The company's claim for cash required in advance of the receipt of revenue to defray the cost of operating and maintenance expenses was deter mined from a revenue-expense lag study employing the same approach approved by the Commission in PP&L's prior rate proceedings. This study, which was based on an analysis of actual historic test year revenue and expense data, indicated an average lag in the receipt of revenue of 34.2 days, which is offset by an average lag in the payment of operating expenses of 20.6 days (PP&L St. 2, p. 22; PP&L Exhibit Historic 1, C-5, p. 2). The resulting net lag in receipt of revenues of 13.6 days was then multiplied by the average daily future test year operating and maintenance expense level of $3,328,000 to derive the $45,261,000 cash investment required of the company's shareholders (PP&L Exhibit Future 1, C-5, p. 2).

Finally, the company has factored into its cash working capital claim the amount of $3,856,000, representing the average balance of certain prepaid items (PP&L Exhibit Future 1, C-5, p. 3). As explained by Mr. Vanderslice (PP&L St. 2, pp. 22-23), these prepayments include insurance, rental, vehicle registration and postage meter expenses which are paid for in cash in advance of the recording of the applicable expense on PP&L's books. Since such prepayments remain on the balance sheet until expensed, they were not reflected in Mr. Vanderslice's expense lag study, but rather create a separate cash working capital requirement.

After determining its cash working capital needs, the company reduced its claim in this case to reflect a lag in the payment of debt interest and preferred stock dividends (PP&L Exhibit Future 1, C-5, pp. 1 & 5-6).

PP&L's claim has not been contested in principle, although as the OCA notes (OCA M.B., p. 100), the company's claim will have to be recomputed in order to reflect any reductions in embedded cost rates and measures of value.

b. Fuel Inventories and Materials and Supplies

In the case of fuel inventory requirements, the company's claim is designed to provide a 50-day supply of bituminous coal at PP&L-operated generating stations (i.e. Brunner Island, Sunbury, Martins Creek and Montour) and a 25-day supply of No. 6 fuel oil for Martins Creek Units Nos. 3 & 4. In all other instances, the claimed amounts of coal and oil at each facility were based on the projected thirteen month average balances expected to be on hand during the future test year (PP&L Exhibit Future 1, C-6, pp. 2-3). The unit prices employed in valuing these quantities use the estimated average inventory prices at July 31, 1983 (PP&L St. 2, p. 26). To these values the company added the applicable fuel stock expense, i.e. principally procurement costs, resulting in a total fuel inventory claim of $177,826,000 (PP&L Exhibit Future 1, C-6, p. 1).

Claimed materials and operating supplies, including undistributed stores expense, equal $22,916,000 (PP&L Exhibit Future 1, C-6, p. 1). This amount represents the company's actual investment in this type of inventory at July 31, 1982, which figure has been employed as a proxy for the estimated balance at future test year end (PP&L St. 2, p. 26).

Trial Staff witness Kalbarczyk has recommended that $28,639,000, or approximately 47% of the company's jurisdictional oil inventory claim, be disallowed. Specifically, Mr. Kalbarczyk's proposal is the product of three separate adjustments -- (1) a repricing of the quantities claimed based on current, i.e., spot oil prices; (2) a reduction in the requested inventory level of No. 6 oil at Martins Creek to reflect a 20-day supply at a 59.3% capacity factor; and (3) the elimination of those volumes of No. 6 oil (128,000 barrels) which he stated represent inactive inventory in the Interstate Energy Company (IEC) pipeline (T.S. St. 12, p. 9).

With respect to the appropriate price to be used, Trial Staff notes that PP&L has priced its oil inventory at $31.67/bbl, while Mr. Kalbarczyk testified that $27.00 should be used based on the April 12, 1983 price of $26.47/bbl. Trial Staff argues that PP&L's actual average inventory value at March 31, 1983 was $28.33/bbl., but current prices to PP&L of $25.02, $25.72 and $26.47 in March and April were not yet fully reflected in the average inventory value such that a downward trend in inventory value is still to be experienced.

PP&L admits that oil prices have fallen below those projected by the company when it prepared this rate filing, but, it maintains, that development alone does not justify the restatement of PP&L's claim at current price levels. Given the volatility of oil prices in the recent past, it argues, there is obviously no guarantee or, for that matter, reason to believe that the present depressed market conditions will prevail for any appreciable length of time. As noted by PP&L witness Snyder, Manager-Fuel Purchasing and Transportation for the company, PP&L was advised on March 30, 1983 by Scallop Oil Corporation, one of the company's three largest suppliers, of an impending increase in the price of No. 6 oil. Two weeks later on April 12, 1983, Scallop implemented an additional price increase (Tr. 2679). The prices of its other primary suppliers have also increased (Tr. 2679). These developments suggest that oil prices may well resume their normal inflationary course in the next few months (PP&L St. R-8, pp. 3-4).

Finally, PP&L argues, even if some recognition were to be given to the recent decline in oil prices, Mr. Kalbarczyk erred in revaluing the company's entire claim at the then-current delivered price. As explained by Mr. Snyder (PP&L St. R-8, pp. 4-5), PP&L utilizes the "average cost" valuation method which serves to moderate the impact of sharp swings in prices. As a result, even though the delivered price of oil decreased during the future test year, the average value of fuel in inventory declined at a substantially slower rate (PP&L St. R-8, p. 5).

While it is true that the price of oil is highly volatile, it makes little sense to project an average July 31, 1983 price which bears little resemblance to present realities. As Trial Staff notes, PP&L's average inventory value at March 31, 1983 was $28.33/bbl., but current prices to PP&L of $25.02, $25.72 and $26.47 in March and April were not yet fully reflected in the average inventory value.

In view of the present trends in world and national prices of oil, Mr. Kalbarczyk's average estimate of $27.00/bbl. for No. 6 oil appears to be nearer the mark of what PP&L will actually be experiencing than the company's estimate made last fall. Trial Staff's adjustment with respect to repricing of petroleum inventories should be adopted.

The next issue concerns PP&L's claimed 25-day active reserve requirement at Martins Creek. Staff witness Kalbarczyk testified that, in his opinion, a 20-day reserve was adequate (T.S. St. No. 12, p. 7). PP&L witness Snyder stated in his direct testimony that PP&L maintains a 25-day burn inventory at Martins Creek and, in his rebuttal testimony, that a 24-day inventory was maintained (PP&L St. R-8, p. 9). He stated, however, on cross-examination that the company's February 1983 Fossil Fuel Report (T.S. Exhibit 12-B) actually indicated a 10 to 25-day inventory "target range" (Tr. 2690). According to Trial Staff, the chart in its Exhibit 12-B, showing actual days supply on hand at Martins Creek each month from July 1981 to January 1983, included both active inventory and some five days' worth of inactive inventory (Tr. 2692). Adjusting these inventories downward by five days to indicate actual active heavy oil inventory maintained over the period would effectively adjust the active inventory "target range" to 5 to 20 days and, Trial Staff claims, would indicate that historic levels of heavy oil active inventory maintained at Martins Creek were to a great extent far below the 25-day level claimed by the company in this case and much more in line with the 20-day figure recommended by Mr. Kalbarczyk.

Trial Staff claims that PP&L has proposed to include in rate base an active inventory level of 1,400,000 bbls. -- a level sufficient to maintain a burn rate of 56,000 bbls./day for 25 days. The 56,000 bbls./day consumption equates to an average daily capacity factor for Martins Creek Unit 3 and Unit 4 of 86.2% for 25 days (T.S. St. No. 12, p. 5). Trial Staff argues that this is far greater than any experienced capacity factor for such units. The record indicates that Martins Creek Units 3 and 4 will operate at only a 33.7% capacity factor for the test period (T.S. St. No. 12, p. 5) and that the highest annual capacity factor ever experienced at Martins Creek was 44%; the highest monthly figure ever was 69.8% and PP&L projects a capacity factor of 49.6% as the highest for any month in the test year (T.S. St. No. 12, p. 6). On this basis, Trial Staff argues that the 56,000 bbl./day figure is unreasonable. Trial Staff witness Kalbarczyk recommended use of a capacity factor of 59.3%, which equates to a burn rate of 38,525 bbls./day (T.S. St. No. 12, p. 6). The 59.3% figure also equates to generation of 700,000 MWH/month and is some 20% higher than projected needs (T.S. St. No. 12, p. 6; T.S. Exhibit 12-A, Sch. 3; PP&L Exhibit 200.182119, Attachment 4).

PP&L argues that Mr. Kalbarczyk's recommended adjustment to the claimed level of No. 6 oil for Martins Creek Units Nos. 3 and 4 should be rejected. First, it argues, the 59.6% capacity factor which he employed in his calculations is purely arbitrary and was apparently selected merely because it would provide, in his view, a "safety margin" over the highest monthly output rates for those two units anticipated by the company during the future test year (T.S. St. 12, p. 6).

The company argues that what it has projected to occur under normal operating conditions is logically irrelevant in determining the level of inventory which should be kept on hand. Since the company is statutorily obligated to provide reliable service, accordingly, it must be prepared to meet whatever exigencies may arise. PP&L witness Snyder stated that (PP&L St. R-8, pp. 6-7) Martins Creek Units Nos. 3 and 4 operated during the winter of 1978 at a capacity factor in excess of the 86% burn rate used by the company for planning purposes for a period of 31 days. Again, in January 1980, the monthly capacity factor for these two units approximated 70%, indicating that they could have run at an 86% rate for a 25 day period (Tr. 1663). Within the past two months, weekly capacity factors for both units have exceeded 60% and would have exceeded 80% but for certain mechanical problems (PP&L St. R-8, p. 7).

In view of the above, PP&L argues that it would be irresponsible for PP&L to assume a 59% capacity factor in assessing its inventory requirements for Martins Creek Units Nos. 3 and 4.

The company also maintains that Mr. Kalbarczyk's proposed 20-day supply of No. 6 oil is unsupported and was apparently the result of his misunderstanding of the company's response to a Trial Staff interrogatory (PP&L Exhibit 200.182055). In its answer, PP&L observed that during certain disruptions ". . . a period of at least three weeks could elapse from the time a new supply is contracted for and oil enters the pipeline." On the basis of this response, Mr. Kalbarczyk erroneously concluded that even under the most dire conditions the company could "replenish oil stocks at MC 3 & 4 in 21 days" (T. S. St. 12, p. 7).

PP&L maintains that the three weeks referred to in the company's interrogatory answer does not include the time required to pump the oil up the pipeline from Marcus Hook to Martins Creek. This process normally consumes four days (PP&L St. R-8, p. 9) which, when added to the 21 days relied upon by Mr. Kalbarczyk, produces the 25 day supply period requested by PP&L. The three week figure cited in the company's response assumes that a new supply of oil has been contracted for. Mr. Snyder testified that PP&L's suppliers have demanded at least 30 days notification in advance of delivery and in tight market situations can be expected to exercise that contractual right (PP&L St. R-8, p. 8). As such, PP&L maintains, the 25-day inventory level claimed by the company is clearly conservative and should be approved.

It would appear that the company's estimated consumption at Martins Creek is far in excess of any experienced at that facility -- so far in excess as to leap the bounds of reality. Mr. Kalbarczyk's estimate, which itself is some 20% greater than PP&L's projected needs, should be adopted.

It would appear, however, that the company's claim of a 25-day supply is more reasonable since Mr. Kalbarzyk's estimate apparently fails to reflect the time needed to pump this oil up from Marcus Hook and contractual delivery delays.

Trial Staff argues also that the company has claimed in rate base 320,000 bbls. of inactive inventory -- inventory that is not usable but is required to maintain the deliverability of oil from transmission and storage facilities. Included in that amount is some 50,000 bbls. of inactive inventory in the IEC pipeline (Tr. 2697). Trial Staff notes that IEC is a wholly-owned subsidiary of PP&L and serves three customers, PP&L, Pennsylvania Electric Company and Jersey Central Power and Light Company (T.S. St. No. 12, p. 8). Trial Staff notes that IEC claims none of the 128,000 bbl. inactive reserve and PP&L apparently allocates the requirement among itself and the other two customers of IEC (Tr. 2698). PP&L originally owned all 128,000 bbls. of oil in the IEC line (Tr. 2698), but Trial Staff maintains the company failed to substantiate that the remaining 78,000 bbls. of inactive inventory not claimed in rate base in the current case (128,000 - 50,000) had been transferred to other customers and were not "buried" in PP&L's claimed inventory (Tr. 2698).

Trial Staff argues that IEC's inactive inventories should be reflected as part of the pipeline's rate base and not financed by PP&L's ratepayers. At a minimum, therefore, Trial Staff recommends the disallowance of the 50,000 bbls. admitted by the company to reflect its allocation of the IEC inactive inventory. PP&L argues that the oil in the pipeline is not the property of, or owned by, IEC. For that reason, its carrying costs could not enter into IEC's Pipeline Cost Rate (PP&L St. R-8, p. 10). PP&L is seeking to claim rate base treatment of its allocated share of No. 6 oil in the pipeline during the historic test year. The oil belongs to PP&L; it is necessary to keep that oil in the pipeline for the operation of that facility. It is properly includable as part of PP&L's rate base.

OCA witness Cotton proposed a $3,338,000 reduction in the amount claimed for coal inventories to reflect latest average test year inventory prices (OCA St. No. 5B, Sch. 10 Revised).

PP&L argues that Mr. Cotton seeks to recognize the recent decline in coal prices while simultaneously ignoring all other costs which have exceeded the company's future test year estimates. As in the case of oil, it claims, the price of coal is subject to constant fluctuation and there is no assurance that it will not rise again in the near future. In this regard, PP&L witness Snyder noted that the current United Mine Workers' contract is scheduled to expire next year and that it is likely that buyers, fearing a reoccurrence of the past two work stoppages, will attempt to build up their inventories in anticipation of a potential strike (PP&L St. R-8, p. 12). That factor, together with improving business conditions, could easily generate an increased demand and price for coal.

The OCA adjustment should be adopted. The mere fact that conditions might change further at some future time is no reason to rely now on an outdated estimate. Here, as with the level of oil prices, the latest available information should be used.

4. Contractor Retentions

Trial Staff witness Gruber proposed the disallowance of 24 contractor retentions amounting to a $1,734,692 ($1,154,000 relating to Susquehanna and $580,688 other) reduction in rate base and a downward adjustment to depreciation expense of $28,892 ($10,892 Susquehanna and $18,000 other).[5/]

As explained by the company, in large construction projects, it is common to provide for the withholding of a portion of the contract price, pending completion of the work. Such a provision is principally designed to protect the buyer and furnishes some assurance that the supplier will comply with the terms and specifications agreed upon. Once the work has been performed, the amounts retained are generally paid out within a few months as part of the orderly process of cleaning up and closing out the contract (PP&L St. R-15, pp. 1-2).

Here, it is agreed by all parties that these are monies due and owing for the construction of plant. All of the facilities to which Mr. Gruber's proposed adjustments relate will have been constructed, placed in service and serving customers by the end of the future test year employed in this proceeding. As such, the dollars in question do not constitute a speculative future expenditure, but rather represent a committed investment in used and useful property. In addition, and as evidenced by Trial Staff Exhibit 13A, some of the retentions at issue will be paid as early as August 1983 and all will have been released shortly after the rates established as the result of this proceeding go into effect.

Trial Staff's adjustment should be rejected. It truly seeks to elevate form over substance. The company, following prudent management practices, has temporarily withheld these payments. These amounts will be paid shortly after the rates established here go into effect. If the company chose not to

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5/ This is on a company-wide basis and reflects a change from the original Trial Staff proposal (T. S. M.B., pp. 10-11).

follow this practice, but rather decided to pay these bills immediately upon receipt, Trial Staff would apparently agree to permit PP&L to earn a return on this investment. Trial Staff, however, seeks to deny the company a return on these monies because PP&L is temporarily withholding payment to make sure these contractors fully comply with their agreements. It makes no sense to penalize a utility for sound business judgment.

B. SUSQUEHANNA ISSUES

1. Excess Capacity

The OCA, Trial Staff and EPEA have sponsored witnesses proposing adjustments to reflect what they term to be excess capacity on the PP&L system. Although Trial Staff's adjustment is actually to revenues and not rate base, for ease of consideration it will be dealt with here.

a. OCA Position

The Office of Consumer Advocate presented as its witness on the subject of excess capacity Dr. Richard A. Rosen (OCA St. No. 4). Dr. Rosen stated that the purpose of his testimony was to review the concept of excess capacity as it affects the issue of whether Susquehanna Unit No. 1 should be included in PP&L's current rate base. His analysis of the PP&L filing resulted in the following seven major conclusions: (1) on the basis of providing reliable service to its ratepayers as defined by PP&L's PJM obligation, PP&L will have more than 1,900 megawatts of excess capacity during 1983; (2) PP&L is probably correct in claiming that some of this capacity is not excess capacity from economic point-of-view, in that energy sales from these units may reduce the cost of service for their own ratepayers; (3) on the other hand, PP&L's claims that Susquehanna eventually will be economically useful to ratepayers, are likely to be incorrect. Thus, at least the 945 megawatts PP&L capacity, corresponding to PP&L's share of Susquehanna Unit No. 1, should presently be considered excess capacity, and not used and useful to ratepayers; (4) specifically, in evaluating the cost effectiveness of Susquehanna, the company's base case analysis has:

a. overestimated fossil fuel prices, as well as the likely capacity factor of Susquehanna, and thus has significantly overestimated the likely future fuel savings of Susquehanna;

b. potentially overestimated load growth for both PJM and PP&L;

c. underestimated the likely operations and maintenance costs of Susquehanna after the 1980's;

(5) review of the PP&L bulk power sales program over the last few years has indicated a relative failure of the effort to establish two party contracts for long-term bulk power sales; (6) a review of the PP&L bulk power sales documents, as well as his own analysis of the PP&L system, leads to the conclusion that there are three types of plant mix that could be considered to comprise the minimum 945 megawatts of excess capacity that will exist on the PP&L system when Susquehanna unit comes on line during 1983. These three plant mixes are: (a) Susquehanna No. 1 only, (b) Susquehanna No. 1 and Martin's Creek 3 and 4, (c) a 12.6% slice of PP&L's complete capacity mix which corresponds to 945 megawatts; and (7) even if an excess capacity adjustment is made by excluding some amount of electrical plant investment from PP&L's rate base, there is no basis in his view for excluding any of the $186,000,000 in energy savings expected to be provided by Susquehanna Unit No. 1 on an annual basis.

Dr. Rosen noted that there are basically two different definitions of excess capacity. First, the reliability definition of excess capacity, which is the situation where there is capacity over and above that necessary to meet peak demand plus that capacity to ensure that there is a margin to allow for day to day variations in the operating condition of installed generation. There is also, he stated, an economic definition of excess capacity where, as here, it is argued that a new facility should not be considered to be excess capacity from an economic point of view, even though the utility has sufficient capacity from a reliability and reserve margin standpoint. The most usual example of the situation is where a new nulcear or coal unit would replace mostly oil-fired generation in a system. The appropriate time frame over which excess capacity can be determined from a reliability standpoint would be on a yearly basis. In contrast, the degree to which excess capacity exists according to the economic definition due to the presence of additional base load units which are deemed to be excess according to the reliability definition can be determined both in the short term and in the long term. The short term might be the period over which the new rates proposed by the company would be in effect. The long term might be the expected lifetime of the unit.

The installed capacity required to maintain reliability under aggregate pool load levels is PP&L's installed capacity obligation to the PJM. This required capacity obligation is calculated according to the provisions of the 1974 PJM supplemental agreement. According to this agreement, the 1983 figure for PP&L is 5,461 megawatts. (Table 1 below taken from PP&L Exhibit No. 200.282066, shows PP&L's projected reserve capacity during the period 1982-2010.) This is 11% of the projected 1983 winter peak of 4920 megawatts. Once Susquehanna Unit No. 1 becomes operational in 1983, PP&L indicates that it will have some 1919 megawatts of excess capacity from a reliability perspective over and above their PJM obligation of 5,461 mw. This implies a reserve margin of 50% of the 1983 winter peak. This excess capacity will not remain idle, but neither will it be needed to provide service to PP&L's ratepayers, Dr. Rosen

Table 1

WINTER LOAD/CAPACITY/RESERVE SUMMARY
1.8% PEAK LOAD GROWTH (1981-2002)[6]
EXPECTED CASE

Year	Peak Load (MW) Summer	Peak Load (MW) Winter	Installed Capacity (MW) Additions	Retire.	Total Planned	Purchases/Sales[3] AE	LU	ACE	Net Installed	Actual Reserves MW	Actual Reserves %	Capacity Obligation[4] Total MW	Req. Reserves MW	Req. Reserves %	Reserve Over Obligation MW	Reserve Over Obligation %
1982	3930	4850	0	0	6546	0	-111	0	6435	1585	32.7	5309	539	11.1	1046	19.4
1983	4050	4920	945(1)	0	7491	65	-114	-62	7380	2460	50.0	5461	541	11.0	1919	35.1
1984	4120	4970	945(1)	0	8436	120	-117	-125	8314	3344	67.3	5651	681	13.7	2663	47.1
1985	4170	4990	50(2)	0	8486	100	-123	-125	8338	3348	67.1	5491	501	10.0	2847	51.8
1986	4220	5170	13(2)	0	8499	80	-97	-125	8357	3187	61.6	5689	519	10.0	2668	46.9
1987	4340	5310	0	0	8499	60	-68	-125	8366	3056	57.6	5840	530	10.0	2526	43.3
1988	4460	5470	0	0	8499	40	-36	-125	8378	2908	53.2	6074	604	11.0	2304	37.9
1989	4600	5590	0	0	8499	15	0	-125	8389	2799	50.1	6203	613	11.0	2186	35.2
1990	4700	5660	0	0	8499	0	0	-125	8374	2714	48.0	6341	681	12.0	2033	32.1
1991	4770	5800	0	0	8499	0	0	0	8499	2699	46.5	6499	699	12.0	2000	30.8
1992	4800	5910	0	0	8499	0	0	0	8499	2589	43.8	6619	709	12.0	1880	28.4
1993	4900	6010	0	0	8499	0	0	0	8499	2489	41.4	6731	721	12.0	1768	26.3
1994	5060	6160	0	0	8499	0	0	0	8499	2339	38.0	6961	801	13.0	1538	22.1
1995	5180	6270	188(5)	0	8687	0	0	0	8687	2417	38.5	7003	813	13.0	1604	22.6
1996	5280	6390	0	0	8687	0	0	0	8687	2297	35.9	7221	831	13.0	1466	20.3
1997	5380	6530	0	0	8687	0	0	0	8687	2157	33.0	7444	914	14.0	1243	16.7
1998	5500	6660	0	0	8687	0	0	0	8687	2027	30.4	7593	933	14.0	1094	14.4
1999	5610	6710	0	0	8687	0	0	0	8687	1977	29.5	7715	1005	15.0	972	12.6
2000	5660	6840	0	0	8687	0	0	0	8687	1847	27.0	7864	1024	15.0	823	10.5
2001	5740	6960	0	0	8687	0	0	0	8687	1727	24.8	8070	1110	16.0	617	7.6
2002	5850	7120	0	0	8687	0	0	0	8687	1567	22.0	8261	1141	16.0	426	5.2
2003	5900	7190	0	0	8687	0	0	0	8687	1497	20.8	8337	1147	16.0	350	4.2
2004	5950	7260	0	0	8687	0	0	0	8687	1427	19.7	8423	1163	16.0	264	3.1
2005	5990	7330	0	0	8687	0	0	0	8687	1357	18.5	8502	1172	16.0	185	2.2
2006	6040	7400	0	0	8687	0	0	0	8687	1287	17.4	8654	1254	17.0	33	0.4
2007	6090	7480	600*	0	9287	0	0	0	9287	1807	24.2	8751	1271	17.0	536	6.1
2008	6140	7550	0	0	9287	0	0	0	9287	1737	23.0	8834	1284	17.0	453	5.1
2009	6190	7620	0	0	9287	0	0	0	9287	1667	21.9	8913	1293	17.0	374	4.2
2010	6240	7690	0	0	9287	0	0	0	9287	1597	20.8	8999	1309	17.0	280	3.2

* - NEW UNITS INSTALLED WHEN RESERVE OVER OBLIGATION FALLS BELOW 0.0%

(1) The Susquehanna units (1050 MW each) will be jointly owned by PP&L (90% - 945 MW) and Allegheny Electric Cooperative Inc. (AE) (10% - 105 MW). Since AE does not require all the capacity initially, PP&L will purchase capacity and energy from them through the late 1980's as shown under sales. In addition, PP&L has entered into an agreement with Atlantic City Electric Company (ACE) under which ACE will purchase, subject to FERC approval, 6.6% of PP&L's share of the capacity and energy from Susquehanna Units (125 MW when both are in-service), beginning with the in-service dates and ending in September 1991. This is also shown under sales.

(2) The Safe Harbor expansion (PP&L share 63 MW) was assumed to be completed in late 1985 and early 1986.

(3) The sales indicated reflect the effect of capacity arrangements with AE and ACE and an estimate of the effect of power supply arrangements with Luzerne Electric Division (LU) of UGI Corporation. For purposes of this report, the expected effects of the LU agreement are reflected as a reduction in PP&L's capacity.

(4) Estimates of capacity obligation are based on PJM allocation method, using reserve margin of PL group. Obligation and reserve above obligation are customarily presented in terms of summer rated capacity. The "Winter" obligation indicated here is an equivalent capacity obligation reflecting winter capacity ratings.

(5) The expansion of the Holtwood Project is assumed in-service in 1995.

(6) Average compound growth rate based on 1981 actual weather adjusted winter peak load exluding UGI. Peak actually occurred in January 1982.

stated. According to PP&L, even after Susquehanna Unit No. 1 is operational most of its plants will operate in a manner almost identical to their performance characteristics as if Susquehanna Unit No. 1 were not operational. Dr. Rosen stated that this fact can be seen by comparing the system dispatch model output that PP&L has provided in PP&L Exhibit 200.282 of the base case and the base case without Susquehanna for 1983. In the former case, Susquehanna Unit No. 1 is projected to produce about 3623 gwh of power in 1983. In this case, the Martin's Creek No. 3 and 4 oil units run at about a 5% lower capacity factor, PP&L sells substantially more coal and oil power to the PJM pool, and, therefore, buys less power from the pool. In fact, Dr. Rosen continues, PP&l's analysis shows that with Susquehanna Unit No. 1 on line they sell about 3738 gwh more to the Pool in 1983 than without this unit. Therefore, their increase in power sales to the Pool is little greater than the total output of Susquehanna Unit No. 1 in that year. According to Dr. Rosen, it is clear that while the 1919 megawatts of excess capacity in 1983 included Susquehanna Unit No. 1, it is merely being used to increase sales power to the Pool. Dr. Rosen concludes that it is not necessary to provide either system reliability or energy for PP&L ratepayers.

According to Dr. Rosen, the basic effect of adding power from Susquehanna Unit No. 1 to the PP&L system in 1983 is to allow PP&L to serve other PJM systems with both the capacity and energy from PP&L's excess generating facilities. Thus, while economic benefits could derive from these sales in 1983 at least, the 945 megawatts being added to the PP&L system in the form of Susquehanna Unit No. 1 is not used and useful for its ratepayers from a reliability or need-for-energy perspective.

Dr. Rosen reviewed the company's analysis presented by Mr. Hecht in his direct testimony (PP&L St. 11) as well as in PP&L Exhibit WSH-3. The analysis, Dr. Rosen stated, consists of a base case scenario and three sensitivity analyses, each of which presumes that one of the three key base case assumptions is altered. The company's base case assumption assumes that Susquehanna will operate at 70% capacity factor when the units are mature. The sensitivity assumption assumes that mature capacity factor is reduced to 60%. The base case assumes also that fossil fuel costs will escalate much faster than inflation through 1990, with coal escalating at 4.5% annually and oil at 5.6% annually above the inflation level. The sensitivity assumption assumes a reduced escalation, but still well above inflation through 1990. The base case assumes that PP&L's peak load will grow at 1.8% annually. The sensitivity assumption assumes that PP&L peak load growth is reduced to 0.8%. As Dr. Rosen describes, the company generally finds that the annual cost of Susquehanna will exceed the annual benefit in the earlier years (1983-1988) but that benefits will begin to predominate later on. The year in which annual net benefits begin is dependent on the particular case considered. Under the base case it would be 1989 and under the reduced load growth sensitivity case, it would be 1991. Dr. Rosen points out that the company's analysis of these extremes of costs and benefits reflects only current dollars. According to the witness, it is entirely inappropriate when analyzing a project whose benefits are postponed so far into the future to consider current dollars. Future benefits should be discounted when compared with nearer term costs, since a dollar today is worth much more than a dollar in the future. Using the company's requested 12.71% weighted cost of capital as the discount rate, under the company's base case assumptions, Dr. Rosen stated, customers will begin to see cumulative benefits from Susquehanna in 1997.

Dr. Rosen also reviewed the assumptions contained in the company's base case. Generally, he found that PP&L has adopted assumptions which will overestimate the likely economic benefits of the Susquehanna units. In his opinion, the company has not correctly forecast nuclear operations and maintenance expense growth. In addition, he believes that the Susquehanna units are more likely to achieve capacity factors in the range of 55% to 65% rather than the 70% which PP&L uses. For this reason he considers the company's sensitivity case assumption of a 60% capacity factor as an appropriate base case of probable value.

He noted that PP&L's base case assumption is that the cost of both coal and oil will rise substantially faster than inflation, particularly in 1982 to 1990, from the peak values that were experienced in 1981. Dr. Rosen said that these assumptions were already seriously flawed. Instead, he believed that fuel price increases will be much closer to the general inflation level, such as those in the company's low fuel sensitivity case. These values, he believed, are more appropriate bases for an analysis of the claims the company is making. Dr. Rosen only briefly reviewed load growth forecast and did not attempt to make an independent demand forecast either for PP&L or the PJM system. Dr. Rosen, after adjusting the company's study of these new assumptions, concludes that the two Susquehanna Nuclear units as a whole will never prove economically used and useful to the PP&L ratepayers. In Table 4 of his statement (OCA St. No. 4), Dr. Rosen summarized his estimates of Susquehanna costs and benefits. Weighing all factors together, he concluded that the likely result is net cumulative losses ranging between $1,500 million and $2,500 million in present value terms.

Dr. Rosen's study, however, does not reflect costs or benefits of Susquehanna after the year 2002. He believed that this was appropriate because long range benefits, when projected more than 20 years in the future, are by their nature highly uncertain.

With respect to the projected expenses of operation and maintenance costs, Dr. Rosen explained that he used a statistical approach of such costs, while PP&L in making its estimates has taken basically an engineering approach. Dr. Rosen noted that PP&L's engineering approach and his statistical approach are in agreement for the period of the mid 1980's. He criticized, however, PP&L's decision to escalate its witness Kenyon's mid-1980 estimates at only the rate of inflation after 1988.

Dr. Rosen stated that, as with nuclear O & M costs, he performed a detailed statistical study of the capacity factors for most commercially operating nuclear units in the United States over the period 1975 to 1981.

Dr. Rosen then reviewed the efforts of PP&L to sell off some of this excess energy and capacity in order to keep rates for their customers at a minimum. He summarized his review in a few points: (1) except for a contract sale of 6.6% of PP&L's share of the output of Susquehanna to Atlantic City Electric until 1991, PP&L has not been able to successfully negotiate any other long-term contracts with bulk power; (2) some short-term power sales have been arranged with Consolidated Edison and Northeast Utilities during the fall of 1982 to continue on a weekly or monthly basis. These sales are projected to continue indefinitely; and (3) until recently PP&L was limiting its long-term sales efforts to full cost recovery including a full return on the capacity and fixed costs of Susquehanna.

Dr. Rosen concluded that given the virtual collapse of the PP&L long-term bulk power sales effort and its inability to sell additional capacity from Susquehanna, the exclusion of at least 945 megawatts or 12.6% of PP&L's capacity from rate base or some other excess capacity adjustment would be appropriate.

b. <u>Rebuttal Testimony of PP&L Witness Dr. Hieronymus</u>

In rebuttal to Dr. Rosen's testimony, PP&L presented William H. Hieronymus (PP&L Statement R-14). Dr. Hieronymus believed that Dr. Rosen erred in his selection and use of the PP&L sensitivity studies of the economic benefits of Susquehanna. In particular, Dr. Hieronymus stated, Dr. Rosen's selection and use of the low capacity scenario is not supported by his analysis and, moreover, Dr. Rosen's capacity factor analysis is itself defective. Dr. Hieronymus believed that Dr. Rosen improperly ignored the benefits of the last 20 years of Susquehanna's forecasted life and understated those benefits which his analysis did encompass due to the use of an incorrect discount factor. Dr. Hieronymus believed that Dr. Rosen's O & M analysis, which is of importance only to post 1990 cost performance, is not reliable. Dr. Hieronymus also believed that Dr. Rosen's recommended exclusion of 945 megawatts of capacity is not supported by his cost-benefit analysis. Finally, he believed that Dr. Rosen's recommendations, even if they were supported by his analysis, would constitute inequitable regulatory policy and produce disincentives to economically efficient behavior.

Specifically, Dr. Hieronymus stated that the PP&L sensitivity studies used by Dr. Rosen for an analysis of Susquehanna cost effectiveness were not constructed for the purpose to which Dr. Rosen used them and are not sufficient to support an analysis of whether Susquehanna would be cost-justified. Rather, these variations are simple and deliberately limited excursions off the PP&L base case, designed to show the impact of various negative assumptions concerning the economic performance of the unit. The first and most obvious deficiency in these studies, he stated, is that they were truncated in 2002, less than 20 years after the Susquehanna units are scheduled to go into operation. According to Dr. Hieronymus, the mere fact of uncertainty in later years is not sufficient to truncate an economic analysis of Susquehanna after 20 years. The use of life cycle analysis is particularly necessary in the utility industry, he stated. A base load power plant, and particularly a nuclear power plant, is characterized by high capital cost and low operating cost. Under regulatory accounting principles, these capital costs have disproportionate impacts on costs in first years. Conversely, the savings in costs which justify the plant are in the form of fuel cost savings and, in some instances, deferral in the need to build new capacity in the future. The cost of inflation and real escalation in fuels and plant construction costs, the value of savings increase over time. By including only the first half of the plant life, he stated, Dr. Rosen is including a disproportionate share of costs, but excluding a disproportionate share of benefits. Dr. Hieronymus stated that a competent cost benefit analysis of Susquehanna must make some assumption concerning its benefits over its last 20 years. By ending his analysis in 2002, Dr. Rosen has assumed that the benefit will be zero. This assumption is without factual support, according to Dr. Hieronymus.

In adopting the combined sensitivity case as his base case for economic analysis purposes, Dr. Hieronymus stated, Dr. Rosen has argued factual propositions which are themselves inconsistent with the cases which he selects on the basis of those propositions. For example, his assertion that the 60% capacity factor case should be used is based on his own generic study of capacity factors, but Dr. Rosen's capacity factor study is not Susquehanna-specific; rather it purports to show that large boiling water reactors, in general, will perform substantially worse than the company anticipates and that large pressurized water reactors in general will perform still worse. Yet, the company's low-capacity factor case, which he relies upon, assumes that all other large nuclear power units in the PJM system will perform much better than the Rosen capacity factor study forecasts, and that only the Susquehanna units will perform at a low level. Implicitly, by using the company's low capacity factor sensitivity case, Dr. Rosen is asserting that his generic study applies to Susquehanna, but not to any other nuclear unit. Because a significant benefit to Susquehanna is derived from interchange sales, this benefit is heavily impacted by the amount of low-cost generation available elsewhere in the PJM system. By relying on a scenario which assumes a low capacity factor for Susquehanna, but higher capacity factors for all other plants, Dr. Rosen has severely biased the analysis, according to Dr. Hieronymus. In addition, all of the scenarios assume the existence of nuclear plants in PJM lasting longer than the 19 or 20 years he assumes for Susquehanna. Dr. Hieronymus stated that this must be regarded as inconsistency to the extent that Dr. Rosen is relying on an uncertain nuclear plant life to motivate truncating his analysis. Dr. Hieronymus also believes that the appropriate discount rate to be used is not the company's pretax weighted average cost of capital. It is simply inappropriate, he stated, to use the 1983 cost of capital as a discount rate for all years unless there is reason to believe that it accurately reflects future values. Such an assumption is not reasonable and, in addition, is inconsistent with the inflation assumptions which underline PP&L witness Hecht's and, therefore, Dr. Rosen's analysis. Because net values are incurred in the initial years of a plant's life and net benefits thereafter, a high discount rate will undervalue its total net benefits. Dr. Hieronymus believed that the correct rate for use in investment analysis is not the pretax cost of capital, but the after tax incremental cost of capital.

Dr. Hieronymus reviewed Dr. Rosen's basis for selecting the company's low capacity factor assumption for the Susquehanna units as a component of his most likely scenario. He derived three principal conclusions on the basis of this review: first, Dr. Rosen's own study, when properly characterized, suggests that the company's base case capacity factor is more realistic than a 60% capacity factor case; second, because of the inherent limitations of historic experience, errors in data, and a convoluted specification of the regression equation, Dr. Rosen's regression produces unstable and unreliable results; third, he believed that Dr. Rosen's regression inadequately estimates the specific performance of a large boiling water reactor, such as Susquehanna Unit No. 1. Dr. Hieronymus stated that PP&L's low capacity factor case does not project a flat 60% capacity factor across the entire life of Susquehanna. In the first four years of operation, the capacity factor in this case averages only 51.2%. Dr. Rosen incorrectly interpreted the scenario of having lowered only the the mature years' capacity factors. In addition, Dr. Hieronymus stated that Dr. Rosen's capacity factor analysis rests on the simple premise that the lifetime performance of new reactors coming on line in the 1980's can be predicted, based on the statistical analysis of reactor performance during the 1975-1981 period. Moreover, it assumes that it is necessary to characterize reactor characteristics only quite crudely; age, size, type and other similar variables are sufficient descriptors. In addition, Dr. Hieronymus criticizes Dr. Rosen's sample for including several small demonstration plants which were built in the 1960's and are not relevant to predicting performance of large modern reactors such as Susquehanna. Similarly, Dr. Rosen's calculations erroneously included Millstone Unit No. 2 in the data base for 1975, although Millstone did not go into service until December of that year. In addition, Dr. Hieronymus criticized Dr. Rosen for failing to treat consistently the extraordinary events which have had extreme impacts on specific reactors. Although Dr. Rosen excluded observations for TMI Unit 2 after the accident in

March of 1979, Dr. Rosen failed to make any adjustment for the abnormally low capacity factors for Brown's Ferry Units 1 and 2 during the years 1975 and 1976, which resulted from the cable fire at those plants. Excluding these observations from the regression analysis would increase the projected immature capacity factor for Susquehanna to 60.2%, essentially identical to the company's 61% forecast of Susquehanna's capacity factor for the first four years of operation. A mature capacity factor, years five through ten, averages 69.7%, which again is quite similar to the company's forecast. According to Dr. Hieronymus, Dr. Rosen's regression-based forecast, when properly interpreted, supports PP&L's forecast of a 70% mature capacity factor. The remaining area of disagreement, Dr. Rosen's forecast of a very low capacity factor in the first four years of operation, is due essentially to five data points. One such point, according to Dr. Hieronumus, is simply an error and the other four related to a single, unique event. If this error is corrected and the impact of the Brown's Ferry outage excluded, Dr. Rosen's approach supports the company's forecast for both mature and immature years.

Dr. Hieronymus testified that he also reviewed Dr. Rosen's study of nuclear O & M expenses. He concluded that Dr. Rosen's study is not a reliable basis for forecasting Susquehanna operation and maintenance expense. His reasons for this conclusion are: one, that the general approach of extrapolating O & M escalation on the basis of a time trend measured over data consisting mostly of the mid to late 1970's experience is not justified; second, a sampling of his data leads to the conclusion that what appeared to be simple calculation errors so affect his data base that any regression based upon it is suspect; third, Dr. Hieronymus stated, Dr. Rosen's equation has poor explanatory power both conceptually and statistically; finally, according to Dr. Hieronymus, there is a clear error in Dr. Rosen's application of the equation to Susquehanna.

Dr. Hieronymus points out that Dr. Rosen's differences with PP&L relate solely to O & M costs in the post 1990 period. Through 1990, there is no dispute concerning the present value of O & M. While Dr. Rosen's data span the 1970's, the bulk of this data is for the period 1975 through 1980. Dr. Hieronymus does not question that O & M costs increased very rapidly over that period, but he explains this increase on the basis of two major regulatory changes: one was the major change in on-site security requirements which occurred in the 1970's; the second was implementation of the TMI action plan in 1979 and 1980. Dr. Rosen's approach does not seek to explain this cost trend, only to measure it. Acceptance of Dr. Rosen's approach, he stated, is tantamount to forecasting that costs will rise in the 1980's and 1990's for no reason other than that they rose in the 1970's. According to Dr. Hieronymus, it is surprising that the same analyst will not project even the existence of Susquehanna past its first 19 years, nor accept his capacity factor regression as having validity past 10 years, will sponsor O & M estimates which are not important until a period beginning 10 years after the end of his analysis period.

Dr. Hieronymus also stated that after examining the 1980 FERC Form 1's on which Dr. Rosen says he relied for his 1980 cost data a number of errors have been uncovered. In addition, Dr. Hieronymus stated, Dr. Rosen treated Susquehanna Unit No. 1 as being a stand-alone facility, instead of a multi-plant station. This error increased the forecasted O & M costs for the unit in every year beginning with 1984.

c. Commission Trial Staff's Excess Capacity Adjustments

The Commission Trial Staff presented two witnesses in the area of excess capacity, Mr. Michael J. Gruber (T.S. St. No. 13) and Dr. James Giordano (T.S. St. No. 17).

Mr. Gruber calculated PP&L's capacity reserve margin (CRM) by dividing total generating capability by native peak load. In the case of PP&L, he stated, this is approximately 49%. In his opinion, this is considerably too high. To obtain his recommended level for PP&L's CRM, he assumed concurrent outages of PP&L's largest unit, Susquehanna Unit No. 1 (945 megawatts), plus Keystone (210 megawatts) and Conemaugh (194 megawatts), the two units on the PP&L system which are not operated by PP&L, and Holtwood Hydro (102 megawatts) and Wallenpaupak (44 megawatts), the company's two hydro stations, for a total generated capacity of 1,495 megawatts. This would give PP&L a CRM of approximately 29.6% over their peak load. Mr. Gruber stated that the level of CRM is a judgment call. In his judgment the 29.6% amount is based on the largest unit in the PP&L system plus those units for which the company has no control over the operation. While he recognizes that the level of CRM can fluctuate depending on the timing of new generation facilities, and that immediately after a new unit is placed into service, the CRM will probably be higher than necessary, but should be expected to return to a reasonable level in the next few years as load growth occurs. However, in the case of PP&L, the CRM would reach 49% in 1983, while the addition of Susquehanna Unit No. 2 in 1984 would increase this amount to 66%. These additions plus that relating to the Safe Harbor expansion along with the fact that no retirements are scheduled for the next 10 years will keep the PP&L CRM as least doubled that required by PJM through 1992. Mr. Gruber stated that the Commission has never decided what the proper CRM should be. Mr. Gruber used this CRM adjustment to develop an amount of available excess generation for sale. In order to find out how much PP&L could generate using their excess capacity of 966 megawatts, Mr. Gruber stated that he had to determine how long the average megawatt on the PP&L system was available for generating electricity. He used 66.2% as his availability factor.

Staff witness Dennis M. Kalbarczyk (T.S. St. No. 16) presented testimony concerning the propriety of a ratemaking adjustment for imputed revenue from off-system sales profits to reflect PP&L's excess generating capacity. Mr. Kalbarczyk stated that the PP&L customer pays a return on all of PP&L's units whether they operate or not. He noted that Staff witness Gruber testified that the company can generate substantially more power than what it has projected and can more than adequately supply its own customers. He noted that current sales contracts with other utilities will not generate profits which can reasonably offset the cost associated with the return to be paid by the customer. In order to encourage PP&L to act more aggressively on behalf of its customers, and taking into consideration that Staff has not recommended removal of any generating plant from rate base, Mr. Kalbarczyk recommended that the 5.6 million megawatt hours identified by Mr. Gruber as excess capacity (T.S. Exhibit 13, Schedule 1, page 3) be valued at an average profit ratio of $12 per megawatt hour and that a total of $67.2 million be included as an adjustment to increase the revenue credit of fuel purchases. The $12 per megawatt number represents the current profit ratio to be realized through sales to other utilities (T.S. Exhibit 16A, Schedule 1). The witness recommended that the ECR be based at zero consistent with the company's intentions. However, for purposes of the computation of base energy costs (PP&L Exhibit Future I-D-3, page 6), he proposed that the 9.683 mills/kilowatt figure incorporated by the company be reduced by $67.2 million for a fuel base of 6.783 mills/kwh.

In summary, the witness recommended modifying the ECR to reflect the following: guaranteed $152.3 million off-system sales profit; guaranteed additional revenues of $67.2 million due to excess capacity; profit from all interchange sales above $219.5 million should be split fifty-fifty between the customer and the company; and the ECR tariff language should be amended accordingly.

It is his opinion that this is the most viable method for the Commission in dealing with PP&L's excess capacity. The method proposed allows and encourages the company to utilize all of its assets while adequately compensating the customer for the rate of return it pays to PP&L. Absent a firm commitment by the company to sell additional power at a reasonable profit, the excess plant should be excluded from rate base.

Dr. Giordano's testimony introduced an alternative revenue adjustment to that proposed by Staff witness Kalbarczyk. Dr. Giordano referred to recent Iowa Commission cases which denied a portion of the equity holder's return on investment in excess generating capacity. This would mean that the equity costs associated with excess capacity would be shared by ratepayers and stockholders. As explained by Dr. Giordano, a revenue deduction is based upon the percentage of total generating capacity which is found to be excessive. That return will be reduced only on the common equity portion of net investment in total generating capacity which represents excess capacity; the excess capacity financed by debt and preferred stock will still command a full return from ratepayers. Third, the revenue reduction will be proportional to the ratio of excess capacity to annual peak load; this means that for a company with a given megawatt annual peak, the dollar adjustment will vary directly with the amount of excess capacity. In other words, the penalty is proportionally greater for a company which overbuilds significantly than for a company which overbuilds only slightly. When applied to PP&L, the return adjustment would be some $6.8 million. In determining excess capacity, Dr. Giordano used Mr. Gruber's figures, i.e., 966 megawatts.

Dr. Giordano also noted that the Iowa method can be easily modified so as to eliminate all of the common equity return on that portion of net investment in total generating capacity which is found to be excessive. This is done by eliminating the ratio of excess capacity to annual peak load from the formula. The net effect of this adjustment is that there is no equity return whatsoever on excess capacity whether it be little or a lot. If this factor were eliminated, the adjustment proposed would be $35.5 million or more than five times greater than the original Iowa adjustment.

d. EPEA Excess Capacity Adjustment

Charles W. King submitted testimony (MI Statement No. 3) dealing with the appropriate treatment of the revenue requirement associated with the Susquehanna nuclear generating unit. Mr. King agreed with MI's witness Siwek's analysis, below;, that in the near term the Susquehanna nuclear units are not cost-justified, and that no net increase in costs should be borne by present ratepayers as a result of the initiation of the Susquehanna units. He did not believe, however, that this conclusion justified the total disallowance from PP&L's rate base and revenue requirements of Susquehanna units. He noted that the company forecasts fuel cost savings of approximately $185,000,000 during the first year of operation of Susquehanna Unit No. 1. These savings would flow through to ratepayers as reductions in energy charges. To allow these benefits to flow through to ratepayers without granting the company offsetting revenue recovery to compensate for the generating plant which made these savings possible would be unreasonable he testified.

Mr. King would include in the company's revenue requirement an amount which exactly equals fuel cost savings and interchange benefits generated by the Susquehanna units. Specifically, the revenue requirement to offset costs associated with Susquehanna Unit No. 1 should equal the forecast $185,000,000 in fuel cost savings and interchange benefits from that plant. He would include some $60,000,000 of this amount for return and income taxes. He noted that PP&L asserts that it requires an after-tax return on investment of 12.71%, which translates into a pre-tax return on investment of 19.90%. The calculation of revenue requirement as previously stated yields a return and income tax amount of $60,000,000. This amount is 19.90% of $301.5 million, which is the amount of Susquehanna investment that he believes should be included in PP&L's rate base for the test year. Since the total investment in Susquehanna Unit No. 1 is approximately $1,500,000,000, the residual extracting the rate base investment would be $1,190,000,000. It is his testimony that a return on this investment should be deferred until such time as the plants of benefits match its cost. He recommended that this amount in non-rate base Susquehanna investment be retained in the Construction Work in Progress Account.

Mr. Siwek's testimony addresses the costs and benefits of the Susquehanna Steam Electric Station (MI Statement No. 2). It is the witness' contention that under all scenarios presented by PP&L the economic burdens borne by current and near term future ratepayers far exceed the costs shown by PP&L. Specifically, the witness criticizes PP&L's Exhibit WFH-3 presented by Mr. Hecht. In that exhibit Mr. Hecht calculates the annual costs and benefits for the period 1983 to 2002 inclusive for Units 1 and 2 of the Susquehanna Station. Mr. Hecht includes as costs of the unit depreciation, return on investment and taxes, as well as operating and maintenance costs. His calculation of benefits considers two types of fuel savings associated with Susquehanna: first, savings on fuel needed to serve PP&L's load; the second type of savings are interchange sales reflecting savings credited to PP&L's ratepayers as a result of the increase in that company's sales to PJM interconnection. The most glaring error, in Mr. Siwek's opinion, is the failure of PP&L to discount the costs and benefits extremes to reflect the time value of money. Mr. Siwek believed that present value discounted is especially important in evaluating the Susquehanna Station because most of the unit's costs occur in the early years, while net benefits will be experienced in the later years. Failure to employ present value discounting thus overstates the net benefits relevant to costs. He noted that Mr. Hecht appeared to suggest two reasons for not discounting costs and benefits associated with Susquehanna. First, Mr. Hecht appeared to distinguish PP&L as a regulated utility from non-regulated firms which would probably make investment decisions on the basis of present value analyses (Tr. 1370). The second argument put forth by Mr. Hecht is that most consumers pay their electric bills out of current revenue. Present value analysis is not, therefore, appropriate since these customers would not be borrowing funds to pay their electric bills from PP&L (Tr. 1371). Mr. Siwek did not believe that either of these arguments were valid ones for ignoring the present value of future costs and benefits extremes.

Mr. Siwek presented Exhibit SS-1, which restates PP&L's base case analysis to reflect discounting at the company's requested rate of return of 12.71%. As a result of his analysis, Mr. Siwek believed that PP&L customers will experience cumulative net savings in excess of their cumulative costs in 1997, some 14 years from the present, and will experience more losses than benefits in all years before that date. The cross-over date would be even further in the future if a reduced capacity factor were used in calculating the benefits from Susquehanna. If PP&L's low-load growth scenario were used, it is possible that the company's ratepayers would never experience positive net savings from Susquehanna, according to Mr. Siwek.

In summary, Mr. Siwek believed that for near term ratepayers the Susquehanna Units are not cost-justified under any reasonable cost-benefit analysis. Furthermore, he believes a real possibility exists that Susquehanna Units 1 and 2 can never be justified economically to PP&L's ratepayers. As a result, he believes that no set increase in cost burdens should be imposed on ratepayers as a result of the installation of the Susquehanna unit.

e. Discussion

In its 1980 Philadelphia Electric Company decision (54 Pa. P.U.C. 220), the Commission defined excess capacity as "capacity over and above that necessary to meet peak demand plus that capacity to ensure that there is a margin to allow for day-to-day variations in the operating conditions of installed generation." Under this, the so-called reliability standard, PP&L clearly, and undisputedly, enjoys a substantial amount of excess capacity. PP&L argues that the reliability standard simply looks at one point in time and under that definition a utility will always have excess capacity when a new base load plant is brought on line. Certainly, it is true that capacity cannot be added megawatt by megawatt. Under most circumstances, the addition of a large base load plant plus the vagaries of the economy, which, despite the plethora of forecasting models floating around, always seem to undermine any set of assumptions, will result in a utility initially having substantial amounts of capacity in excess of its reserve requirements. This utility, however, has capacity well over its requirements for at least the remainder of this century (Table 1, supra). Indeed, even without the addition of Susquehanna, PP&L's present net installed capacity is sufficient to meet the company's projected peak reserve capacity requirements under its own load forecast through 1990 (PP&L Exhibit 200.282066).

The company argues, however, that there may be instances where the addition of a large base load plant may be economically beneficial over a period of time to its ratepayers although not needed on a reliability basis, a position with which Dr. Rosen agrees (OCA St. 4, pp. 8-9).

The various studies of the economic viability of the Susquehanna Units, however, all have serious flaws. Clearly, Mr. Hecht's original study (PP&L Exhibit WFH-3) overstates the economic benefits of the Susquehanna Units over time by its failure to use a discount rate. It is self-evident that the value of a dollar of costs in 1983 is not equal to a dollar of benefits in 2002.

While there may be disputes as to whether Dr. Rosen's use of PP&L's before tax weighted cost of money (12.71%) or an after tax rate of 10% (PP&L St. R-6, p. 18) should be used, it is clear that under the company's base case the Susquehanna plant will not start producing net savings for ratepayers until the end of this decade and that the plant will not produce cumulative net benefits until the mid 1990's at the earliest.

One could, on this record, attempt to speculate as to capacity factors over the next 20 to 40 years, the company's growth rate over that period or how the price of oil will fluctuate. Any conclusion will be wrong. The bottom line, however, of all these studies is that the ratepayers would be better off without Susquehanna from an economic standpoint now and for the foreseeable future. It might well be that the ratepayers over the next 20 years will experience cumulative present worth benefits up to $2.3 billion as shown on the record here (PP&L St. R-6, p. 18), or it might occur that the plant will never produce economic benefits as suggested by Mr. Siwek. The only certainty is that any benefits will first occur on an annual basis well after the rates set here are just a dim memory.

Certainly there has been no suggestion on this record that PP&L has been imprudent in its decisions to construct this plant and to continue rather than defer construction.[6/] But, as the Commonwealth Court stated in its landmark decision in Philadelphia Electric Co. v. Pa. P.U.C., 433 A.2d 620, 622-23 (1981):

> PECO contends that because its decisions to construct the eliminated units as well as its decisions to construct every other of its generating units, when made, were prudent, the PUC may not now remove any of these properties from rate base because there is presently excess capacity. This argument, however, misses the point of the determination. The PUC's order specifically states that the PUC was "not questioning PECO's management decisions made when these units were constructed." The basis for the order is the finding that to the degree that there is excess capacity, there are generating properties which are not used and useful in rendering service to ratepayers.
>
> A unit may be properly excluded from a utility's rate base if the investment in that unit is found to be a result of managerial imprudence occurring at the time the decision to invest was made. See, e.g., UGI Corp. v. Pennsylvania Public Utility Commission, 49 Pa. Cmwlth. 69, 82-87, 410 A.2d 923, 932 (1980). It does not follow that a unit prudently constructed must always be included in the rate base. The touchstone for determining whether or not a prudently constructed unit should be included in a utility's rate base is whether or not, during the test year involved, the unit will be used and useful in rendering service to the public.

Under the circumstances existing here, where the company is seeking to add additional capacity not needed from a reliability perspective, and where any benefit will be delayed well into the future, some "excess capacity" adjustment should be made. Consideration will be given to the three principal proposals set forth on the record.

6/ The Administrative Law Judge, having presided at the Commission's Investigation of the Limerick Nuclear Generating Station, remembers criticism of the utility constructing that plant by several parties, notably Trial Staff, for failing to build those units as swiftly as possible and for choosing, instead, to defer construction with the attendant escalation of costs.

Trial Staff's adjustment is made up of several parts. Mr. Gruber's claim that PP&L will have 966 mw of "excess capacity" in 1983 (T.S. St. 13, p. 3). This capacity is then converted into 5.6 million mwh of "excess generation" based on a unit availability factor of 66.2% (T.S. Exhibit 13-A, Sch. 1, p. 3). Mr. Kalbarczyk calculated the profit of $12/mwh, which he assumed could be realized on the sale of this generation and proposed a revenue adjustment of $67.2 million.

Mr. Gruber's calculations appear to be flawed. He employs an availability factor of 66.2% to calculate mwh of "excess generation," but this figure assumes that a unit is available to generate electricity whenever it is "connected to load" (T.S. St. 13, p. 7). This is not correct. A unit "connected to load" may not be available for generation for a variety of reasons, such as partial outages and that the net available capacity of generating units varies depending on the ambient temperature.

In addition, Mr. Kalbarczyk relies on Mr. Gruber's calculation of "excess generation" to calculate his $66,223,400 revenue adjustment. Because Mr. Gruber's calculation is flawed, so is Mr. Kalbarczyk's adjustment. His adjustment is suspect for other reasons as well. First, he stated that his adjustment will provide PP&L with an "incentive" to increase its off-system sales (T.S. St. 16, pp. 4, 6). He therefore assumes, without any justification, that a market exists for all of Mr. Gruber's "excess generation." This is not correct (PP&L St. R-7, p. 5).

Additionally, Mr. Kalbarczyk assumes that any additional sales would produce the same $12/mwh average profit achieved from PP&L's presently anticipated interchange sales (T.S. St. 16, p. 4). This assumption ignores the principles of economic dispatch. PP&L loads its generating units in the most economic order possible. Lowest cost units are used first to supply PP&L's

own customers and the next most economic units are used to make interchange sales. The additional sales assumed by Mr. Kalbarczyk would, by definition, be made from less economic units and therefore would be less profitable than existing interchange sales. As explained by Mr. Scheffley, the additional sales imputed by Mr. Kalbarczyk would produce a loss in energy savings, and not a gain (PP&L St. R-7, p. 5):

> The reason for this result is quite simple. As discussed earlier, PP&L's low cost coal-fired generation is fully committed. PP&L's oil-fired generation is fully utilized to the extent needed to meet native load and to the extent it can be sold to other utilities. Thus, the additional energy envisioned by Staff can be generated only from the Company's higher cost units, i.e., heavy oil, diesels and combustion turbines. Such energy is not generated because it is too expensive for purchase by other utilities. If generated, it must be used to meet native load. Therefore, Mr. Kalbarczyk's assumptions will result in a net decrease in energy savings and increased costs to our customers.

Dr. Giordano's proposal presents an interesting alternative but has not been thoroughly explored on the record.

EPEA witness King, based on Mr. Siwek's conclusions, proposed that PP&L be allowed to recover and earn a return on its investment in Susquehanna only to the extent that it actually produces energy savings in a given year. He bases this adjustment on the theory that ratepayers should not bear any risk that Susquehanna will not be cost-effective. Under Mr. King's proposal, shareholders bear all of the risk of poor Susquehanna performance, but receive none of the rewards of greater than expected performance. Conversely, ratepayers bear no risk of poor performance and would receive all the benefits of greater than expected performance.

Moreover, under Mr. King's proposal, PP&L would continue to accrue AFUDC on the portion of Susquehanna not included in rate base (M.I. St. 3, p. 5).

This is similar to delaying Susquehanna, which would significantly increase the cost of the plant and would clearly be detrimental to ratepayers. In addition, Mr. King's proposal would violate the FERC Uniform System of Accounts and Statement No. 71 of the Financial Accounting Standards Board.

Under Dr. Rosen's proposal, some 945 mw of capacity, representing PP&L's share of Susquehanna, would be termed excess. Although he identified three different approaches that could be taken to quantify this excess capacity so that revenue adjustment could be made, the approach which is most reasonable, identifies 945 mw of PP&L's complete capacity mix in equal proportions as the excess capacity. This approach was similar to the one undertaken in Philadelphia Electric Co., 54 Pa. P.U.C. 220 (1980). It permits PP&L to recover depreciation and other operating costs associated with the excess megawatts, but does not allow PP&L to earn a return on the net plant investment.

This approach is reasonable and should be adopted by the Commission.

2. Cost of Susquehanna's Construction

A highly controversial issue in this proceeding has been whether PP&L's management of the construction of the $1.7 billion Susquehanna Unit No. 1 was reasonable and prudent.

a. PP&L's Position

Mr. Norman W. Curtis, PP&L's Vice-President - Engineering and Construction - Nuclear Project Director, testified as to the management philosophies used during the design and construction of the Susquehanna project. He also presented testimony as to some of the key factors that have affected the project during its construction stages (PP&L St. 8).

Mr. Curtis stated that the Susquehanna Steam Electric Station is located on the west bank of the Susquehanna River in Salem Township, Luzerne

County, Pennsylvania. The main site within the security fence is approximately 100 acres.

The plant consists of two boiling water reactor (BWR) nuclear generating units, each with a net 1050 MW rating. The reactors and directly related equipment, which together constitute the Nuclear Steam Supply System (NSSS), were designed and supplied by General Electric Company (General Electric or G.E.). The total plant design, engineering, procurement, construction, and related services were provided by Bechtel Power Corporation (Bechtel) under contract to PP&L.

Mr. Curtis further stated that before 1970, PP&L forecast that it would need a substantial amount of new generating capacity to meet customer demand in the 1970's and beyond. To help fill that need, the company decided in 1970 to proceed with plans and preliminary engineering to build a large nuclear power plant. Design work started in September, 1970, and by December 1971, conceptual design was essentially complete. At that time, construction of Unit 1 was expected to begin in the fall of 1972, with commercial operation scheduled for October, 1978. Because of a delay in the receipt of a construction permit from the Atomic Energy Commission (AEC), construction did not actually begin until November, 1973. Construction of Unit 1 was completed and the plant loaded fuel on July 27, 1982. As noted earlier, commercial operation for Susquehanna Unit 1 began on June 8, 1983.

Bechtel was responsible for total plant design, with the exception of the NSSS, Turbine Generator, and the Advanced Control Room. These three major components were designed by General Electric. Although G.E. and Bechtel provided extensive design services for the project, PP&L had overall responsibility to ensure that Susquehanna would be a safe, reliable, and economical plant. PP&L established a staff of personnel to take an active role in reviewing design specifications and drawings. Also, PP&L evaluated and approved all major engineering changes in order to maintain control of the design process as it evolved.

During the 1970's, Mr. Curtis testified, the number of nuclear safety and environmental regulations increased dramatically. These new standards imposed stricter design, manufacturing and construction requirements on Susquehanna and the remainder of the nuclear industry. When the various regulatory agencies ordered incorporation of new regulatory requirements, changes in design, fabrication, construction and testing were necessary. In many instances, extensive retrofitting was required which contributed to delays in the construction schedule. The new regulations required more and more new analysis, studies and tests. All phases of the design process required accumulation of substantial records to document engineering calculations. Mr. Curtis testified that regulatory changes and design evolution had a considerable effect on Susquehanna, particularly upon the cost of the project.

In addition, the series of events that occurred at Three Mile Island (TMI) on March 28, 1979, had a considerable effect on the Susquehanna project. As a result of the accident, many new safety regulations requiring hardware, procedural and documentation changes were initiated.

In addition to the hardware changes, various studies were required to analyze critical plant systems. Also, many new procedures, training programs and additional plant personnel were required to ensure plant safety. The direct cost of these improvements was considerable. Mr. Curtis also stated that the indirect costs associated with TMI, namely, effect on project schedule, were difficult to ascertain.

In summary, he testified, the TMI incident served to increase Susquehanna's scope, schedule and cost significantly. Mr. Curtis stated that not all design changes on Susquehanna were a result of new regulations; some changes were incorporated to improve the operational capabilities of the plant.

The company's philosophy behind non-regulatory changes undertaken to improve operational capabilities was to minimize non-regulatory design changes. Only those changes that would provide cost-effective operability and maintainability enhancements were incorporated into the plant design. PP&L made Bechtel responsible for essentially all procurement. Bechtel also acted as PP&L's agent in administering the NSSS contract.

The general procedures used for procuring material and equipment, he stated, were similar to those used on most other nuclear construction projects. The respective engineering groups defined material and equipment requirements in the form of specifications. Agents or buyers then transmitted the approved specifications as bid requests to selected vendors. Upon receipt of bids, the Purchasing Department coordinated their evaluation and the recommendation of an award.

In order to effectively monitor Bechtel's performance in this area, PP&L, he stated, played an active role in the entire procurement process. Prior to bid solicitation, PP&L was responsible for reviewing and approving specifications and lists of approved bidders. After receipt of bids, PP&L reviewed Bechtel contract award recommendations and had the final approval authority. Mr. Curtis stated that throughout the course of the project, PP&L maintained an engineering staff which has been involved in establishing and maintaining standards of design quality.

He testified that PP&L also maintained an active role in design development. It directly managed many technical programs, defined requirements, established technical and schedule objectives and managed consultants with specialized experience in the investigation and resolutions of special work tasks.

It jointly developed the conceptual design of the project in conjunction with Bechtel and General Electric. It directed the preparation of the Preliminary Safety Analysis Report (PSAR) and participated with Bechtel, General Electric and other consultants in construction permit hearings and Nuclear Regulatory Commission (NRC) meetings. Its previous corporate experience in the design and construction of fossil plants was factored into the preliminary design. It prepared the Final Safety Analysis Report (FSAR) with input from Bechtel, G.E. and many consultants.

Mr. Curtis testified that the key decisions on the project have been made or reviewed for adequacy by PP&L. These decisions have been based upon corporate studies or recommendations of Bechtel, G.E. or consultants.

Mr. Curtis also stated that a high quality design control program has been in effect throughout the project. This program has been based upon formal procedures, work instructions, a change control program, formal transmittals of design data, design inputs and outputs, a strong architect engineer/nuclear steam system supplier/PP&L cooperation, special design reviews, and a substantial quality assurance program.

PP&L's construction management approach on Susquehanna was to utilize Bechtel to manage, apply cost control methods, schedule and be responsible for all construction of the project.

Mr. Curtis stated that PP&L's role was to provide project direction and to monitor contractors' performance against that direction. This definition of each group's responsibilities, he stated, minimized duplication of effort and fostered an efficient approach to managing the complex construction effort of Susquehanna.

Labor performance was closely monitored by utilizing both computerized and manual control systems. He stated, for example, that throughout the construction process, production data was distributed to the executive management levels of both Bechtel and PP&L. When these documents indicated less than anticipated productivity, steps to uncover the causes were initiated, and corrective action was implemented. On the working level, productivity was monitored in great detail by Bechtel Cost Engineers who advised project supervision of individual crew performance. He testified that by using this data, construction superintendents were able to investigate problem areas and initiate corrective measures that had a beneficial effect on productivity.

Mr. Curtis testified that PP&L's management role has changed over the years in order to be more responsive to the project's needs. Since the beginning of the project, it has become more involved by increasing its personnel and performing more work itself and has implemented numerous management programs so as to improve project performance. PP&L established a site project manager in order to achieve better visibility and to provide more effective communications with the Bechtel project manager. It also initiated monthly project team review meetings between Bechtel and PP&L, which included executive management levels from both groups. It established and implemented an integrated scheduling group to provide a more cohesive measurement of project performance for use in management decision-making process.

Overall, as the project progressed and became more complex, Mr. Curtis testified, PP&L recognized the need for increased involvement. Mr. Curtis stated that PP&L assembled a sizeable staff to control and monitor costs on the Susquehanna project. It also used many control programs. For example, he testified, throughout the project various types of reports which tracked key cost factors were generated. Over the years, he stated, the contents and formats of the reports were modified in order to be more relevant and to focus on current issues.

These many tracking devices, he testified, enable project management to stay abreast of major cost developments as they occurred. In addition, PP&L frequently evaluated management effectiveness by initiating internal and third party audits. These audits evaluated performance in various areas including procurement practices, subcontractor administration, site security, Bechtel Engineering, etc.

Over the years, he stated, it has been a project policy to follow up on any deficiencies uncovered in the audits and take the necessary steps to correct the reported problems. In general, the many audits performed on Susquehanna have had a beneficial effect by identifying ways of improving management practices and thus improving project performance.

Mr. Curtis stated that PP&L utilized an aggressive scheduling technique for Susquehanna. Target dates were established and maintained as long as practical in order to foster a competitive environment on the Project. When it was felt that additional resources or overtime could promote schedule gains, PP&L actively pursued this course. Its effort in this area was sucessful, he stated, in that Susquehanna's construction duration was less than average for other similar plants constructed during the same time frame.

Mr. Curtis listed the most important factors that affected project costs as:

(a) New regulatory requirements

(b) Natural evolution and improvement of design

(c) Schedule delay

(d) Inflation

(e) Labor productivity

These factors, on an individual basis, were significant, he stated, but a greater impact was felt when collectively these factors interacted with each other to increase costs even further.

Susquehanna was similar to other nuclear plants constructed during this time frame, he stated, and was greatly affected by all of the above factors. While PP&L minimized cost increases where possible, the key factors that escalated costs were difficult or impossible to control.

Mr. Curtis believed that the basic fixed fee-cost reimbursable contract with Bechtel enabled PP&L to have a direct voice in the management of Susquehanna. The utility's active involvement in the design and licensing processes allowed it to stay abreast of regulatory developments. This awareness, he believed, was instrumental in preventing additional licensing and construction delays and was successful in making Susquehanna's construction duration one of the shortest when compared to similar facilities constructed in the same time frame. This shorter schedule minimized costs and enabled its customers to benefit much earlier from the energy produced by Susquehanna. It was his opinion that a total cost of $1.7 billion is reasonable and fair for such a project.

PP&L also presented Mr. Robert C. Traylor, Senior Vice-President of Management Analysis Company, who supervised a comprehensive evaluation of PP&L's management of the Susquehanna project. This audit, presented in the record as PP&L Exhibit RCT-1, concludes that the utility's management was effective and prudent. The audit specifically finds that (pp. 211-213):

> PP&L management decisions and actions relative to Susquehanna, evaluated during the conduct of this study, demonstrated that its management consistently understood its basic mission - to provide an adequate and reliable supply of electricity to its customers at a reasonable cost. The projected cost of Susquehanna as of December 1980, adjusted to dollars per kilowatt, was near average for plants compared in this study.

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Our historical review of Susquehanna identified some areas in which PP&L's performance was considered superior to the nuclear utility industry. PP&L demonstrated a technical competence and awareness which we considered unusual and exceptional for a utility undertaking its first nuclear project. PP&L is currently recognized in the utility industry as a technical leader primarily due to the significant contributions and aggressiveness of the company in the analysis and resolution of the Boiling Water Reactor hydrodynamic load problems. We consider PP&L's emphasis on safety and reliability in the design and construction of the plant to be prudent and responsive to its obligations. The importance of safety to PP&L was paramount. Plant reliability was a major factor in all of PP&L's decisions, considering that the overall cost of generating electricity includes operations and maintenance.

* * *

The first objective of this study was to determine the propriety and accuracy of Susquehanna's cost estimates. The estimating process throughout the project fulfilled the criteria by which we evaluated it. The cost estimates were consistently prepared in sufficient detail to assure accuracy. Given the assumptions on which they were based, Susquehanna's cost estimates were proper and accurate. We do believe that optimistic schedule assumptions between 1977 and 1979 resulted in predictions of plant costs much lower than now realized.

* * *

The second objective of this study was to identify the major factors which influenced the cost and progress of Susquehanna. Our overall conclusion is that forces outside of PP&L's management control had the greatest impact on Susquehanna's cost and progress.

* * *

The third objective ot this study was to determine whether management decisions and methods were prudent under the circumstances, recognizing that conditions have changed over time.

PP&L's initial decisions on Susquehanna consistently fulfilled our criteria for being proper. The decisions which we evaluated were prudent and the resultant action was reasonably taken.

In managing the project, PP&L was aware of its responsibilities and was aggressive in fulfilling them. Notwithstanding those areas where the need for improvement was identified, PP&L's performance in managing the project was better than we expected of a utility building its first and only nuclear plant. In general, we find that in the circumstances of a highly turbulent environment, PP&L demonstrated prudent management by continual reassessment of project performance and formulation of strategies to deal with the potential changes of the future.

The final objective ot this study was to determine whether Susquehanna's costs were proper and reasonable. . . . As a company, PP&L examined itself, was examined by others and changed when necessary to improve its effectiveness and efficiency in managing Susquehanna. Overall, we believe that PP&L's management of Susquehanna was both proper and reasonable.

b. OCA Position

The OCA, on the basis of testimony presented by its witnesses Minor and Bidenbaugh (OCA St. No. 3), proposes that some $182.5 million of Unit No. 1 costs be disallowed. This equates to a rate base adjustment of some $146,970,000. These disallowances fall within six cost groups and will be considered individually.

(1) Containment Problems

The Susquehanna containment structure is a concrete structure surrounding the nuclear reactor. Its purpose is to contain radioactivity in the event of failure of the reactor vessel or associated components. The containment concept at Susquehanna was developed by GE and is identified as a Mark II containment (PP&L St. R-5, p. 2). It consists of a drywell and a wetwell, which are separated by a concrete diaphragm slab.

The drywell surrounds the reactor and associated equipment. The wetwell is located directly underneath the drywell and contains 23 feet of water (Tr. 880). The wetwell serves as a suppression chamber to condense steam released from the drywell and thereby reduce the pressure exerted on the containment structure.

As explained on the record, a steam release could occur in two ways - from the opening of the safety relief valves (SRVs), or from a loss of coolant accident (LOCA). In the SRV system, 16 SRV lines are attached to the four primary steam lines which run from the reactor to the turbine. The steam released when the SRVs open travels down these four pipes, through the diaphragm slab and into the pressure suppression pool in the wetwell. This venting occurs as a part of normal reactor operations (PP&L St. R-5, p. 4).

The other source of a steam release is a loss of coolant accident, which could result from a major pipe break in the reactor cooling system. In the event of such an accident, large amounts of steam would be released into the drywell and would be vented into the wetwell through large downcomer vent pipes. In accordance with NRC requirements, Susquehanna is designed to withstand such an event (PP&L St. R-5, p. 5).

Steam released into the wetwell during SRV openings or LOCA creates forces or loads in the wetwell which may be transferred to the rest of the reactor building. The Mark II containment, such as that used at Susquehanna, was designed to withstand these conditions as they were understood at the time the Mark II containment was developed (PP&L St. R-5, pp. 2-3). It should be noted that the Atomic Energy Commission (AEC) approved the Mark II design and issued a number of construction licenses for plants with this design during the 1960's and 1970's, including Susquehanna in 1973 (PP&L St. R-5, pp. 2-3).

In the early 1970's, two independent problems began to be seen. At certain operating Mark I units (the predecessor to Mark II) it was discovered that SRV discharges into the wetwell caused vibration of the pool structure. This problem was first identified as potentially significant in late 1974 and early 1975. During the same period (1973-74), testing by GE on its then-new Mark III containment revealed that the hydrodynamic loads produced during a hypothetical LOCA were greater than previously anticipated (PP&L St. R-5, pp. 4-5).

The NRC first notified BWR owners of these newly identified hydrodynamic loads in 1975, and required owners to evaluate and analyze these loads, and prove that their containments would meet the simultaneous occurrence of these loads and a 0.1g earthquake (PP&L St. R-5, p. 6).

After receiving notice from the NRC, PP&L formed a task force with Bechtel and GE to evaluate Susquehanna's design in light of the newly identified SRV and LOCA loads. A preliminary study completed by Bechtel in May 1975 recommended additional reinforcing steel and relocation of certain equipment. This recommendation was adopted, and the work was performed (PP&L St. R-5, p. 8).

At the same time, PP&L undertook the formation of BWR Owners' Group to study the newly identified SRV and LOCA loads in more detail (PP&L St. R-5, p. 7). PP&L subsequently discovered that the Owners' Group was not on a timetable which would satisfy Susquehanna's schedule requirements and looked elsewhere for a solution to these problems (PP&L St. R-5, p. 8). With respect to the SRV issue, PP&L believed that the SRV loads could be modified by the attachment of a "quencher" to the end of the SRV discharge pipes in the wetwell. PP&L contracted with Kraftwerk Union (KWU), a German company actively engaged in quencher design at that time, to design a special quencher for Susquehanna. This design was available by 1979 and was ultimately used in all but one Mark II plant in the nation as a solution to the new SRV loads (PP&L St. R-5, pp. 8-9).

With respect to the newly identified LOCA loads, while the problem was first identified in 1975, many years of further testing were required to determine the exact nature of these LOCA loads and what impact they would have in combination with SRV and earthquake loads. As with the SRV loads, PP&L

worked with the BWR Owners' Group and KWU to solve the problem. In 1980, KWU produced final design loads for Susquehanna which incorporated the effects of SRV, LOCA and a 0.1g earthquake. These loads were identified as Phase III loads (PP&L St. R-5, p. 9; OCA St. 3, p. 19).

The tests leading to the development of the Phase III loads demonstrated that the original containment design was sound and met all NRC requirements. However, implementation of the Phase III loads did require the installation of a large number of new pipe hangers and some rework to move or replace hangers and other equipment installed on the basis of earlier loads (PP&L St. R-5, p. 9).

Because the LOCA and SRV loading phenomena are imposed on the base mat which supports the containment, the reactor, and many critical piping systems making up the heart of the plant, almost every safety-related system required redesign and strengthening. Due to the problem of continuing construction while the loads were being finalized, PP&L had three different sets of loads used during the project life. Phase 0 loads were those initially used and Phases I and II were interim loads used from approximately 1977 through 1981. In March 1981, PP&L decided to go with loads supplied by KWU because the Mark II generic program was delayed. These loads, designated as Phase III, were used for the final design of hangers and supports. In resolving the Mark II problems at Susquehanna, thousands of piping and conduit support modifications were required, relocation of wetwell equipment was necessary, and strengthening of the containment diaphragm floor was required.

OCA argues that until 1974-1975, the SRV and LOCA load impacts upon the containment were overlooked in designing the plant. When these loads were first recognized, Unit No. 1 construction was well underway. Had PP&L acted sooner and been more diligent in the supervision of GE, these design deficiencies could have been avoided. The OCA argues that the ratepayers should not be required to bear the costs of these oversights.

There is no support for this adjustment.

First, it is undisputed that PP&L's expenditures to solve the containment problem were necessary to build a safe and licensable plant. Failure to expend these dollars would have resulted in a completed plant without a license. PP&L's effort to evaluate and incorporate the new loads in the design of Susquehanna was prudent and essential to commercial operation of the plant and the investment to solve this problem should be recognized in rate base. Secondly, there is no showing 7/ that GE was imprudent in the design of the Mark II containment.

The record shows that GE analyzed both Mark I and Mark II containments and the Mark II design was repeatedly approved by the AEC and was purchased by many utilities. Additionally, OCA has failed to demonstrate that the containment problem was reasonably discoverable by GE at any earlier point in time. The SRV loads were first identified at operating Mark I plants (PP&L St. R-5, p. 4). The additional LOCA loads were discovered during testing at GE's Mark III test facility, which was not even constructed until 1973.

Finally, the problem here was not identifying the loads, but determining the impact of these loads on the plant and how to design for these impacts. As explained by Mr. Curtis (Tr. 2737):

> Q. Mr. Curtis, on page 2 of Mr. Bridenbaugh's surrebuttal at lines 19 to 22, he indicates that the test facilities and instrumentation design capabilities were such that they could have easily detected the load problems if the decision had been made to perform representative tests to confirm the Mark I and II designs.

7/ Assuming that the issue of GE's responsibility for any design deficiencies should be addressed here - an assumption the ALJ is not prepared to make.

> Was detection of the loads the principal aspect of the containment problem?
>
> A. The containment problem as experienced by both the Mark I and Mark II plants required approximately six or seven years to resolve. Identification of the major effects of those loads was identified quite early in the game and quite easily.
>
> The major challenge was one of probing the causes of those effects, understanding the physical principles involved and the theory behind those principles then translating that into a significant determination of the loadings to be applied for design of structures and plant facilities.
>
> It was in that latter area that the industry, including PP&L, experienced a great deal of difficulty in using existing technology to probe those areas. A good part of the program was developed to fundamental physics, understanding the phenomena relating to bubbles and water and a great deal of innovation was required for both analytical purposes and testing purposes to get to the end result.

Resolution of the new loads problem required years of study and analysis and was substantially aided by the development of new state of the art techniques in this field and by the use of more sophisticated testing facilities and instrumentation which were not available when the problem first arose.

In addition, there are serious deficiencies in the calculation of the $38.6 million adjustment sought by the OCA. This adjustment is divided into three parts: (1) $2.7 million for wetwell modification; (2) $32 million for pipe hanger rework; and (3) $3.8 million for an alleged excessive number of pipe hangers in Unit 1 (OCA St. 5B, Sched. 7, p. 3).

With respect to the $2.7 million in wetwell modifications, the evidence supports the conclusion that these modifications were not rework, but would have been incurred even if the containment problem had been solved originally.

Similarly, a substantial portion of the costs identified by the OCA for pipe hanger rework would have been incurred even without the new loads problem since, due to new NRC requirements and general design evolution, a hanger design based on the original hydrodynamic loads would not have been sufficient to obtain a license from the NRC (Tr. 961-62). Since PP&L's cost tracking system did not segregate hanger rework caused by new loads and hanger rework caused by other developments (PP&L St. R-5, p. 13), a substantial portion of the OCA adjustment is for work that would have occurred even without the new loads.

In addition, when the new loads were first identified in 1975, PP&L was faced with a choice of stopping work on the plant while the problem was resolved, or using a set of assumed loads and continuing construction in parallel with the containment technical program. PP&L chose the latter course. The record shows that at the time of these decisions, PP&L recognized that some rework might be required. The cost of this rework, most of which resulted from modification of pipe hangers, was small when compared to the cost penalty of not continuing and completing the plant with its attendant increase in AFUDC costs. Its decisions to proceed with those design and construction activities were made knowing that final test results and design loads being built into the plant would ultimately have to be reconciled. The fact that Susquehanna's Phase III loads were higher than earlier loads could not have been known at that time. Had it waited for Phase III loads, it would have risked project delays for potentially no reason, if the earlier load definition had been shown to be adequate. This was a prudent management decision.

The remainder of the OCA's containment direct cost adjustment is a $3.8 million deduction based on the current difference in number of hangers between Unit 1 and Common, and Unit 2 (OCA St. 5B, Sch. 7, p. 3). This amounts to some 631 hangers. The record shows, however, that some 500 of the hangers included in this adjustment are located in the turbine building, which was not affected by the new loads problem (PP&L St. R-5, p. 14). Second, because Unit 2 is not complete and more hangers are currently being added, the number of so-called excess hangers is overstated.

(2) Schedule Delays

The OCA argues that the record here indicates that plant constrution was delayed by one year as a result of the failure to calculate correctly the hydrodynamic loads for the plant. Considering, however, all activities which occurred in the final stages of the project, the OCA recommends that the six month delay immediately preceding fuel load and Unit 1 (from February 27, 1982 to July 27, 1982) be considered as related to the containment loads modifications and that rate base be reduced by $125 million ($100.7 million on a jurisdictional basis).

There is no evidence to support a finding that the new loads problem was by itself responsible for a delay in fuel load for six or twelve months. While there is no doubt that this containment problem increased the work at this project, so did several other critical activities. The existence of all these factors prevented fuel load from occurring prior to July 1982. These factors, shown in Attachment 1 to PP&L Statement R-5 and attached to this decision as Appendix A, demonstrate that many activities impacted the loading of fuel.

In addition, the six-month figure has no record support. Indeed, the only support is contained in OCA Statement No. 3, pp. 42-43, where the OCA witnesses state:

> Forecast II reflected a delayed fuel load of approximately one year, primarily to permit such changes. Because of concern expressed by PP&L that the NRC might have delayed fuel load through a delay in licensing even if containment were not an issue, we have decided to reduce the project delay adjustment to less than the full year. Monthly reports (e.g. January 1982) indicated that licensing was no longer considered critical as of year-end 1981 and Mr. Curtis confirmed that fact upon cross-examination (Tr. 1048). We therefore recommended a cost reduction equivalent to the extra project management and AFUDC costs related to a six months delay period (January-June 1982).

Even if licensing were not on the critical path to completion in December 1981 as asserted by MHB, this hardly supports an adjustment of $100 million. All this means is that some other area or areas were then projected to take at least one day longer than licensing, and that areas other than licensing prevented fuel load prior to July 1982.

The OCA's six-month schedule adjustment is not supported by any meaningful record evidence and should therefore be rejected.

Furthermore, as stated earlier, I find no evidence to substantiate the claim that PP&L was imprudent with respect to the problems arising out of the containment structure.

(3) Intergranular Stress Corrosion Cracking

OCA proposes a $2.1 million ($1.7 million on a PUC jurisdictional basis) adjustment for improvements to certain piping designed to reduce the possibility of intergranular stress corrosion cracking (IGSCC) (OCA St. No. 3, pp. 27-28).

The OCA adjustment is based on PP&L's contention that GE is responsible for the costs associated with IGSCC. According to PP&L, GE argues that the work associated with IGSCC produced an improved product which will require less maintenance, and that no contract adjustment is appropriate (PP&L

St. R-5, p. 21). Moreover, the utility argues, as with the containment problem, that IGSCC is a problem generic to the nuclear industry and this rate proceeding is clearly an inappropriate and inadequate forum to resolve whether GE has some responsibility or whether a better product has been produced.

The OCA has not shown that expenditures on the IGSCC problem were wasteful, extravagant or imprudent. This rate base adjustment is based solely upon PP&L's allegations that GE is responsible for these costs and that the recommended changes do not result in a better product. These claims will someday be litigated. In that forum it might be shown that PP&L is right. On the other hand, GE might be right that it has no responsibility for this problem. When this is litigated, after the completion of Susquehanna Unit No. 2 in 1984, the appropriate rate base treatment can be determined.

If the Commission acts before these claims have been litigated in the appropriate forum to eliminate these costs from rate base, 8/ a utility would have little incentive to contest what it considers to be improper charges by a contractor. Certainly there would be no incentive if every claim made by the utility against a contractor, whether eventually sustained or not in another forum, resulted in a reduced rate base. While, on the other hand, if the utility had kept silent, it would be earning a return on its investment. Such a policy would only encourage utility acquiesence in inflated and improper claims. The utility, however, will be directed to report in its next rate filing as to the status of its claim against GE. If this claim is resolved at that time, the Commission can take appropriate action.

8/ A finding which might well be *res judicata* in subsequent proceedings. See Pa. P.U.C. v. Philadelphia Electric Co., 433, A.2d 620 (1981).

(4) Electrical Equipment

The OCA proposed a $3.5 million ($2.9 million on a PUC jurisdictional basis) rate base adjustment for rework associated with certain electrical problems experienced during Susquehanna's construction. The basic support provided for this adjustment is PP&L's deficiency notice to Bechtel on this issue and an audit performed by EG&G, an independent consulting firm, which reported certain deficiencies in PP&L's quality assurance for electrical items in the Advanced Control Room (OCA St. 3, pp. 30-32). Neither of these documents support the OCA's adjustment.

Once again, the evidence does not support the adjustment claimed. Under the PP&L/Bechtel contract, PP&L must notify Bechtel of deficiencies within 30 days of discovery. The issuance of these notices is a regular part of supervising any construction project. It does not in any way establish that Bechtel's performance was deficient.

The audit finding appears to be unrelated to the electrical problems in the Advanced Control Room. The record shows that this audit was performed in order to investigate the extent and underlying causes of several problems involving the fabrication of control panels in the Advanced Control Room. The audit finding cited by the OCA criticized PP&L for its lack of Quality Assurance and Quality Control involvement in the supply of the ACR by GE. The cable replacement and voltage drop problems are related to Bechtel design and construction activities, in which PP&L's quality programs are significantly different and more involved.

It would appear that PP&L acted prudently in notifying Bechtel that a potential deficiency existed. When Susquehanna is finally finished, the responsibility for this work can be determined and any adjustment made. Any adjustment now would be premature for the reasons stated above. Again, PP&L should report to the Commission in its next rate filing as to the status of these claims.

In addition, there is an apparent discrepancy in the cost of the electrical problems adjustment sponsored by the OCA. The assumptions used in arriving at the adjustment overstate the portion of Cost Trend 10-4-110 which is associated with the electrical voltage drop problem. The adjustment assumes that 5% of Bechtel's Plant Design group manhours in Cost Trend 10-4-110 are related to voltage drop. None of the Plant Design manhours are, in fact, related to the voltage drop problem since this problem was solved by Bechtel's electrical engineering group, for which the manhours are already included in the adjustment. The record indicates that the Unit 1 value for this work included in Trend 10-4-110 would be approximately $50,000 (PP&L St. R-5, p. 23).

In addition, the treatment of Cost Trend 10-5-46, as defined in Note 3 to Table 2 of OCA Statement No. 3, apparently incorrectly allocates portions of the cost of this work between Units 1 and 2. The allocation assumes that the cost of adding interposing relays is the same as the cost of pulling new cables. The record indicates that the cost of pulling new cables on Unit 2 is higher than the cost of interposing relays which was implemented on Unit 1. PP&L claims that only $220,000 should be associated with Unit 1.

Another overstatement of adjustments is due to the assumption that all of Forecast Item 11-16 for replacement of Unit 1 single conductor cable is associated solely with Unit 1. In fact, the company argues, many of these cables are related to Common facilities or Common equipment. For that portion related to Common facilities or equipment, only one-half of the costs are related to this rate filing (PP&L St. No. R-5, p. 24).

(5) Expansion Anchors

As explained by the OCA, expansion anchors are used to attach structures such as pipe supports, cable trays and pieces of equipment to walls, ceiling or floors of the SSES buildings. They may be used to support equipment which is important to safety or safety-related items (often referred to as "Q" anchors) and are expected to maintain the integrity of their support function during earthquakes and peak loading during transients and accidents. PP&L estimated there are over 121,000 expansion anchors. When it was discovered that some expansion anchors were not properly installed, an audit was performed and eventually an inspection of all 48,000 "Q" anchors was undertaken (OCA St. No. 3, p. 35). The defective design and installation of these anchors was brought to PP&L's attention by an inspection prompted by an NRC directive and a letter from Bechtel dated December 2, 1980. About 5,000 expansion anchors were reinspected and many were redesigned and replaced. The OCA proposes a $2.4 million rate base ($1.9 million on a jurisdictional basis) adjustment.

PP&L contends that the various problems with expansion anchors were not unique to Susquehanna, as demonstrated by the imposition of stricter inspection criteria by the NRC in recent years. The company believes that the problems were largely outside of the control of PP&L and were industry-wide in nature. Finally, the company maintains it acted prudently in undertaking an inspection effort to assure the plant's overall safety and that the amount of rework incurred as a result of expansion anchor problems was not unreasonable in light of the complex nature of the project. No adjustment should be made since this appears to be a problem not within the control of PP&L.

(6) Advanced Control Room

OCA proposes an adjustment of $520,000 ($418,800 on a jurisdictional basis) for unrecovered backcharges for extra work by GE on the Advanced Control Room.[9/]

As explained by the OCA (OCA St. No. 3, pp. 39-40), PP&L elected to not use the conventional BWR control room normally supplied by GE, but instead selected the Nuclenet option which is a computer based integrated display system and smaller control boards mounted on floor sections (Power Generation Control Complex [PGCC]). PP&L, however, also chose to not use the standard configuration for Nuclenet and worked with GE to define their own ACR configuration of stand-up benchboards and back-up panels. In addition to its other unique features, Susquehanna was the first reactor to receive a complete ACR/PGCD control room.

As would be likely during a first-of-a-kind design, there were many problems which had not been worked out fully before the Susquehanna ACR/PGCC was shipped to the field; a fact recognized by the OCA. These problems included workmanship problems and some cable lengths which required shortening.

There is no showing that PP&L has been imprudent. This control room was the first of its kind and some problems are normal. In addition, GE has disputed this backcharge and any adjustment now would be premature. PP&L should report to the Commission in its next rate filing on the status of these claims against GE.

9/ This represents the unrecovered portion of the $1,947,268 backcharge that PP&L sought from GE.

(7) Hydrodynamic Load Studies

Both the company and the OCA agree that the company erred in its allocation of the cost of special hydrodynamic load studies between Units 1 and 2. PP&L's rate base claim for Unit 1 and half of Common should be reduced by $3.1 million on a 100% basis or $2.8 million related to PP&L's 90% share (PP&L St. R-5, p. 26).

(8) AFUDC Adjustment

In view of the above recommended treatment of the OCA's adjustments, Mr. Cotton's proposed adjustment to the AFUDC accrued on Unit 1 should be rejected.

c. Trial Staff's Adjustment

The Commission's Trial Staff, through its witness Michael Gruber, also proposed an adjustment to rate base to reflect what it considers to be improper costs of construction of Susquehanna Unit No. 1.

Trial Staff notes that PP&L has itemized 72 construction defects against Bechtel and 5 against General Electric (T.S. Exhibit 13-A, Sch. 4). Trial Staff states that it has repeatedly attempted to have PP&L quantify the construction costs associated with the repair of these items, but without success.

Trial Staff maintains that the defects listed by the company represent costs which should be the responsibility of the contractors and not PP&L's ratepayers. Trial Staff notes that PP&L is currently involved in various phases of litigation to recover from the contractors some or all of the costs associated with each noted defect. However, it states, because of the company's refusal to supply detailed cost information essential to the calculation of an accurate adjustment, it is required to estimate the construction cost increment represented by repair of the noted defects. Staff witness Gruber proposed a downward adjustment of 10% to the claimed original cost of SSES Unit 1 ($166,650,900 -- $149,976,000 on a jurisdictional-only basis) as his best engineering estimate of the appropriate disallowance for construction defects -- associated with his adjustment was a concomitant reduction of $1,483,193 ($1,334,786 jurisdictional-only) to PP&L's claimed annual depreciation expense.

PP&L notes that the Trial Staff does not allege that PP&L was imprudent or in any way caused these deficiencies. It simply attempts to hold PP&L vicariously liable for contractors' errors without any proof of PP&L imprudence or liability on the part of Bechtel.

Moreover, PP&L argues, Trial Staff's only support for its claim of alleged Bechtel imprudence is PP&L's notices of potential deficiencies filed with Bechtel during the course of construction. As noted earlier, under the PP&L/Bechtel contract, PP&L must notify Bechtel of deficiencies within 30 days of discovery. These notices do not create a legal deficiency on Bechtel's part entitling PP&L to recover the cost of the alleged deficiency. I agree with the company that such notices are not sufficient to support a finding of imprudence by Bechtel.

In addition, I believe that any such adjustment at this time would be premature. PP&L has not recovered from Bechtel on any of these notices of alleged deficiencies. If it is subsequently discovered that Bechtel's performance was deficient, PP&L will no doubt pursue all appropriate remedies to recover the cost of these deficiencies, and any recovery will be applied to the benefit of ratepayers.

Trial Staff, moreover, has produced no evidentiary support for its proposed 10% adjustment. Mr. Gruber has performed no analysis of the notices of alleged deficiences or the disputes underlying these notices (Tr. 2298-99). His 10% figure is based solely on the fact that various engineering studies he has seen contain a cost factor of 10% as a contingency in case of a mistake in estimating a bid. The $166 million rate base adjustment proposed by Trial Staff has no evidentiary support.

The fact that PP&L was unable/unwilling to quantify the adjustment Trial Staff wanted to make is of no moment. If Trial Staff wished to quantify the value of the Bechtel claims, it could have requested access to the information required for such a task, as the OCA did in preparing its proposed cost adjustments.

Finally, PP&L's inability to quantify the value of the Bechtel claims at this time seems justified. Review and quantification of these claims will be a complex and massive task, and would require the use of personnel who are needed for the compeltion of Unit 2. In addition, Mr. Curtis' explanation of the difficulties such an investigation would create bears repeating (PP&L St. R-5, p. 28):

> In my opinion, it would not be prudent to conduct such an investigation and evaluation of the Bechtel notices while Unit 2 is still under construction. Extensive investigation of the Bechtel notices clearly would have a significant disruptive influence on PP&L's relationship with Bechtel and could cause a delay in the completion of Unit 2. The Bechtel notices can be fully evaluated when the plant is completed. Benefits of earlier investigation of the Bechtel notices simply are not worth the risk of schedule delay.

PP&L's decision to defer quantification of the Bechtel claims until Susquehanna construction is completed appears reasonable. Delay on the construction of Unit 2 would cost approximately $1 million per day. Clearly, it is not in the interests of ratepayers to create a situation which will cause a slippage in this construction schedule.

PP&L has paid its contractors the monies involved here. It has disputed some of these costs and has notified these contractors of its position. These issues will be decided after all work at Susquehanna is complete.10/ When these disputes are resolved, the appropriate rate base treatment for any amounts found to be due PP&L can be determined. It would be the height of folly to penalize the utility by making downward adjustments to rate base in anticipation of a favorable resolution of the company's claim. Such adjustments would be speculative and would only encourage a utility not to contest contractor claims. Again, PP&L should report on the status of these claims in its next filing. When these claims are settled, the Commission can determine the appropriate rate base treatment of any recoveries from the contractors.

V. RATE OF RETURN

The issue of rate of return was contested actively by PP&L, the OCA and the Trial Staff. Two other parties, the Department of Defense (DD) and Branch 39 of the Utility Consumers Union of CEPA and the Susquehanna Alliance (CEPA - SA) addressed the rate of return question in their briefs. In the interests of brevity, a lengthy discussion of the various parties' positions will be omitted.

A. Capital Structure

PP&L recommends an estimated July 31, 1983 capital structure of 47.1% debt, 18.1% preferred and preference stock and 34.8% common equity. The

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10/ By agreement of PP&L and the contractors, there will be no problem with the Statute of Limitations.

OCA and Trial Staff accept PP&L's position. It is recommended that the company's capital structure be used.

B. Cost of Debt

PP&L recommends a debt cost rate of 10.92% which reflects the latest available cost rates, including the February 14, 1983 issuance of $50 million first mortgage bonds. It also reflects the use of a prime rate estimate of 11% in the determination of the composite cost of PP&L's secured term notes and revolving credit line. The OCA and Trial Staff accept PP&L's position. It is recommended that the company's cost rate be used.

C. Cost of Preferred and Preference Stock

PP&L recommends a preferred and preference stock cost rate of 9.57% which reflects the latest (May 1983) issuance with a dividend cost rate of 11%. The OCA and Trial Staff accept PP&L's position. It is recommended that this cost rate be used.

D. Cost of Common Equity

The following table summarizes the common equity cost rate methodologies and recommendations of the active parties.

Method	PP&L Brennan[1] %	OCA Rothschild[2] %	Trial Staff O'Donnell[3] %
Discounted Cash Flow	15.3	14.15-14.69	14.93-15.43
Bare Rent	17.0		
Capital Asset Pricing Model	16.0-19.1		14.28
Comparable Earnings Pricing Technique (CEPT)		14.2-14.7	
Claimed Common Equity Cost Rate	17.0	14.75	15.5

1. The common equity cost rate ratios are found in PP&L Exhibit JFB-1, Schedule 1, pages 3-5. All cost rate ratios are not adjusted for the effect of income tax free dividend or market pressure and issuance expenses.

2. The common equity cost rate ratios are found in the OCA Main Brief, pages 105-108. The OCA cost rate range does not reflect an allowance of .3% for financing costs. Further, the OCA does not adjust for the income tax free dividend.

3. The common equity cost rate ratios are found in Trial Staff Exhibit 8A, Schedule 10-13. Trial Staff does not adjust its common equity cost rates for market pressure and issuance expense or effect of the income tax free dividend.

CEPA - SA support the assumptions and methodology of OCA witness Rothschild, but contend that due to improved market conditions, past adverse economic conditions and the inclusion of Susquehanna in rate base, even OCA witness Rothschild's recommendations are excessive. The Department of Defense believes the cost of equity falls in the 14.5 to 17% range for PP&L.

In reaching a common equity recommendation here, the ALJ will rely upon the two rate of return methodologies currently used by the Commission in its most recent cases: the DCF method and the bare rent theory plus risk premium for common equity. The following table summarizes the dividend yield and growth rate recommendations of the active parties.

DCF	PP&L %	OCA %	TS %
Dividend Yield	12.1	11.19 - 11.53	10.43
Growth Rate	3.3	2.96 - 3.16	4.5 - 5.0

PP&L's dividend yield is the average of November 3, 1982 spot and the 12 months ending October 31, 1982. Current yield reflects next period growth in dividend and average yield reflects next period growth in dividends. PP&L's growth rate is the average of the historic earnings growth and projected earnings growth.

The OCA used the December 31, 1982 dividend yield of PP&L (11.05%) increased by a 0.3% allowance for possible future interest rates and an adjustment of .18 - 19% to reflect one year future growth in dividend yields. The OCA growth rate was based on earnings and retention ratio estimates which produce a reinvestment growth projection of 3.54 to 3.74%. The growth rate was adjusted downward by 0.58% to reflect effect of selling below book value on the earnings per share. This results in a growth rate of 2.96 - 3.16%.

Trial Staff's dividend yield is the spot yield as of April 20, 1983 (10.43%) based on actual PP&L data. Trial Staff's growth rate ranges from 4.5%, based Value Line 1979-81 to 1985-87, to 5% using the Salomon Brothers projection of the next five years.

After reviewing the testimony of the witnesses, it would appear that a dividend yield of 11.51% is reasonable. This conclusion is arrived at on the basis of two calculations, each using PP&L witness Brennan's twelve month average yield of 12.3% as of October 31, 1982 and (1) Trial Staff's April 30, 1983 spot dividend yield to generate an average dividend yield of 11.3%, and (2) a spot June 13, 1983 dividend yield of 11% to generate a dividend yield of 11.65%. Averaging the 11.37% and 11.65% yield would produce a recommended yield of 11.51%. The use of the twelve month average dividend yield as of October 31, 1982 and the spot dividend yields as of April 20, 1983 and June 13, 1983 blends historic data with the current investor evaluation thus giving a balanced dividend yield which is neither dated and stale nor one biased by the abnormalities that might be reflected in spot data.

The growth rate recommendation of PP&L is based upon an averaging of historic and projected earnings and dividend growth rates. The ALJ accepts PP&L's 3.3% as a reasonable estimate and an equitable one, balancing the historic and the future time frames.

Therefore, the ALJ's DCF recommendation is 14.81% (11.51% + 3.3% = 14.81%).

The bare rent theory plus risk premium for common equity method has been accepted by the Commission in recent cases and has been used as a primary cost of common equity technique here by Mr. Brennan. On the basis of recent Commission policy, the ALJ has given the bare rent theory plus risk premium for common equity method equal weight with the DCF method in reaching a recommendation here.

Witness Brennan's risk spread analysis, a version of the bare rent theory plus risk premium for common equity, produces a common equity cost rate of 17.0% based upon a forecast of A-rated public utility bond yields of 13.0% for 1983, and a 4.0% risk premium based upon a study of fifty electric companies between 1978 and March 1982. From this study, Mr. Brennan concluded that when bonds last yielded 13%, the spread for common equity was 4.0%.

OCA witness Rothschild also provided a bare rent theory and bond equity study and concluded that under these methodologies the cost of equity would be 12.0-14.3% after adjustment for financing costs, and 15% respectively. However, the OCA did not employ this method as a cost of equity determinant.

The ALJ concludes that under the bare rent theory plus risk premium, a cost of equity of 16.23% based upon the effective recent experienced cost of first mortgage bonds for PP&L of 12.23% as of February 1983. Due to the lack of evidence concerning the risk premium for common equity, the ALJ accepts PP&L's 4.0% recommendation. The use of an actual PP&L debt cost rate in this case provides a more accurate representation of investor opinion concerning PP&L than the use of an estimated debt cost rate.

Therefore, based on an unadjusted DCF and bare rent theory plus risk premium for common equity, the ALJ recommends a common equity cost rate of 15.5% (DCF 14.81% + Bare Rent 16.23% = 31.04 ÷ 2 = 15.52%).

This Commission in numerous recent proceedings has disallowed an adjustment for market pressure and/or issuance expenses. Furthermore, in a world where annual common stock issuances are a normal occurrence, the average investor would have included in his analysis of the cost of common stock the costs, if any, resulting from market pressure and issuance expenses. The ALJ, therefore, recommends the disallowance of an adjustment for market pressure and/or issuance expenses.

PP&L also seeks a 1.3% adjustment to the common equity cost rate due to the change in the tax-free status of its dividend. This income tax-free dividend cost rate adjustment requires acceptance of the belief that the benefit of income tax-free dividends exceeds the increased cost of capital resulting from excessive levels of AFUDC which give rise to the tax-free status. The ALJ also questions PP&L's assumption that PP&L's dividend will move from a 100% tax-free status in 1982 to a 100% taxable status in 1984.

Summary of Recommendation

Type of Capital	Ratio %	Cost Rate %	Weighted Cost &
Debt	47.1	10.92	5.14
Preferred & Preference Stock	18.1	9.57	1.73
Common Equity	34.8	15.5	5.39
	100.0		12.36

Under the recommended 12.36% rate of return, the interest coverage levels on an after income tax basis is 2.4 times. The 2.4 times coverage level surpasses those experienced by the barometer groups used by PP&L and Trial Staff.

VI. REVENUES

As explained by PP&L, the development of its future test year pro forma revenue claim started with the statement of revenues for the appropriate months as set forth in PP&L's 1982 and 1983 Budgets. The figures contained therein are based in large measure on the company's short-term sales forecast. (PP&L St. 6, pp. 21-23).

In accordance with Commission practice, Pennsylvania jurisdictional budgeted revenues were adjusted to eliminate the revenues and associated expenses recovered under the State Tax Adjustment Clause. In addition, the budgeted figures were adjusted to reflect (1) the full recovery of energy costs through proposed base rates and (2) a full-year's operation of Susquehanna Unit 1 (PP&L St. 3, p. 5; PP&L St. 5, p. 6; PP&L Exhibit Future 1, D-3, p. 1). Further adjustments were made to recognize an increase in revenues attributable to certain delayed payment charges and the elimination of unbilled revenues (PP&L Exhibit Future 1, D-3 pp. 1-2).

Budgeted revenues have also been adjusted for customer load growth to reflect sales levels at July 31, 1983. Consistent with the Commission's final Order at Docket Number R-80031114, PP&L separately annualized the effect of changes in the number of customers and in the usage of existing customers. These two adjustments, which were described by PP&L witness Baldwin (PP&L St. 5, pp. 8-10), increase operating revenues by approximately $13.5 million (PP&L Exhibit Regs. III-D-8, p. 7). As noted by the company in its most recent quarterly report (PP&L Exhibit MJB-9C), the anticipated increased revenue levels have failed to materialize.

The issues which have been raised with respect to PP&L's pro forma revenue claim relate to Trial Staff witness Kalbarczyk's proposal that additional operating revenues be imputed due to excess generating capacity. This specific adjustment has been rejected, supra.

In addition, Trial Staff proposes that the company's ECR be modified to assure guarantee of projected off-system sales profits. This will be considered infra.

VII. OPERATING AND MAINTENANCE EXPENSE

A. NON-SUSQUEHANNA ISSUES

1. Wages and Employee Benefits

The budgetary procedures employed by PP&L to estimate payroll costs were testified to by PP&L witness Berish (PP&L St. 4, pp. 9-12).

First, Mr. Berish stated (PP&L St. 4, pp. 11-12) PP&L's 1983 Budget assumed that Susquehanna Unit 1 would commence commercial operation on May 15, 1983. Since all costs incurred prior to that date were capitalized for budget purposes, it was necessary to adjust operating and maintenance expenses, including wages and employee benefits, to reflect a normal ongoing level of annual costs associated with that facility (PP&L Exhibit Future 1, D-11, pp. 1-2).

In addition, budgeted non-Susquehanna wages and employee benefits were adjusted to reflect the number and compensation of employees at the end of the future test year (PP&L Exhibit Future 1, D-5 and D-6). These two adjustments, according to Mr. Bernini (PP&L St. 3, pp. 8-9), were required to depict the level of expense which the company will actually incur during the period in which new rates are in effect. These adjustments were calculated in the same manner reviewed and approved by the Commission in PP&L's previous rate proceedings.

Trial Staff witness L. B. Jones proposed that approximately $1.5 million of PP&L's wage expense claim be disallowed (T.S. St. 7, p. 6).

Specifically, Mr. Jones contends that the company has overstated its overtime requirements and, on that basis, recommends that the budgeted amount be reduced to reflect the average overtime percentage (6.725%) experienced during the four twelve-month periods preceding the future test year (T.S. Exhibit 7-A, Schedule 5). He arrived at an overtime allowance for this rate case of $1,516,696 less than that claimed by the utility (T.S. Exhibit 7-A, Schedule 5).

Mr. Jones' proposed adjustment should be rejected. First, as PP&L points out, its overtime expense is not budgeted by applying a specific percentage to total wages but rather is separately estimated by each individual cost area (PP&L St. R-2, p. 2). The 7.7% figure to which Mr. Jones objects was the product of the company's budgetary process and not a blanket upward factor.

In addition, Mr. Jones' recommended four-year historic average fails to take into account the factors which contributed to an increase in overtime expense over that period. PP&L witness Berish noted that in March 1981 the company implemented a new policy under which certain non-union employees could qualify for overtime pay (PP&L St. R-2, pp. 2-4). That program, which was subsequently refined in January 1982, was designed to (1) maintain adequate differentials between non-union personnel and those they supervise, (2) enable PP&L to compete in the job market for skilled personnel and (3) provide fair value for services rendered (PP&L St. R-2, p. 3).

Because this change was not initiated until early 1981, its full impact would have only been felt in the last (i.e., the historic test year) of the four years analyzed by Mr. Jones. The company's claim in this case (7.7%) represents only a slight increase over the level of overtime actually experienced during that most recent twelve month period (7.6%).

Consumer Advocate witness Cotton recommended that PP&L's claim for pension expense be reduced by $624,000 (OCA St. 5B, p. 1 & Schedule 13). The basis for this proposal was an interrogatory response (PP&L Exhibit 200.282188) which indicated that, based on the latest retirement plan actuarial data, annualized pension costs will fall short of the level requested by the company in this proceeding by this amount.

PP&L argues that the OCA adjustment ignores the fact that during the first seven months of the future test year actual employee benefit costs, including pensions, were some $1.2 million higher than budgeted (PP&L St. R-1, p. 2). Any decline in estimated pension expenses has, therefore, been more than offset by increases in the costs to provide other benefits.

This item presents a difficult case. Here, PP&L argues that the general overall category of employee benefit expenses, of which pension costs are but a part, have increased during the test year over previous estimates and that it is unfair to single out but one item of these costs for correction.

While sympathetic to the company's position in the abstract, I must recommend that the OCA position be adopted. Here we have an admittedly incorrect item - pension costs - which the company admits is overstated by some $600,000. The Commission would fail in its statutory responsibilities if it ignored this error.

2. <u>Rate Case Expense</u>

PP&L has claimed $232,000 as the rate case expense to be incurred in the litigation of the proceeding. This claim is only one-half of the actual amount estimated to be spent and reflects the previous Commission policy of sharing rate case expense equally between ratepayers and shareholders which existed at the time this rate filing was proposed. PP&L seeks to recover this amount over one year (PP&L St. 3, p. 9).

OCA witness Cotton (OCA St. 5, p. 31) recommended an 18 month "normalization" period while Trial Staff witness, L. B. Jones, recommended a two year period.

Given PP&L's recent rate case history of three proceedings in 3.5 years and the almost certainty of a new filing next year, a 12 month "normalization" period appears most appropriate. The company's claim should be adopted.

Mr. Jones also proposed that the cost of the audit (some $1.2 million) performed by Management Analysis Company (the MAC Audit) of the Susquehanna plant be treated as rate case expense instead of being capitalized as part of the cost of SSES Unit 1 (T.S. St. 14, pp. 3-4). This audit, while undoubtedly undertaken with a view towards using it in a proceeding such as this one, was not specifically conducted for purposes of this rate case. Rate case expense claims should not be cluttered with extraneous, albeit tangentially related, matters. Trial Staff's adjustment is denied.

3. <u>EEI Media Advertising</u>

PP&L has claimed some $474,000 for test year dues to the Edison Electric Institute (EEI). Both Trial Staff (T.S. St. 7, p. 4) and the OCA (OCA St. 5, p. 34) seek to reduce this claim by $174,000, reflecting the portion of annual dues used for EEI's national advertising and communications programs. Both parties claim that these advertisements do not provide a benefit to PP&L's ratepayers.

PP&L argues that this program has value. Mr. Berish of the company testified (PP&L St. R-2, p. 5):

> In my opinion, the advertising sponsored by EEI benefits ratepayers in a number of important respects. First, it provides customers with a valuable source of information on such topics as

conservation, energy efficiency and safety. Secondly, by responding to and counteracting, at least in part, the adverse publicity which has been generated in the past few years due to the oil embargo, concerns over nuclear power, etc., EEI-sponsored advertising presents potential investors with a balanced view of the industry. To the extent that these efforts are successful in restoring the faith of the financial community in electric utilities, ratepayers will clearly benefit through lower capital costs. Finally, EEI advertising serves to educate electric utility customers on a variety of issues which can and do have a tremendous effect on the quality and cost of the service which they are provided. Although some of the advertisements may be controversial, the topics they address will, in the future, have a very significant impact on PP&L's customers. The sooner customers realize the consequences of various regulations, policies or procedures, the more informed they will be in either supporting or opposing many critical decisions facing the utility industry in the future. All of these critical decisions will have either a direct impact on them or their environment or an indirect impact through the rates they will be required to pay.

The Commission considered a similar adjustment in its recent decision in Duquesne Light Co. (R-821945, Order entered January 28, 1983). There the Commission stated (pp. 26-27):

> The Respondent contends that Media Communication dues represent expenditures for the purpose of informing the public regarding energy needs, energy sources, and the viability of the electric utilities, all to the ultimate benefit of ratepayers.
>
> The ALJ considered the record to be replete with examples of EEI sponsored media advertising dealing with such items as energy conservation (Duquesne Exhibit 31J; Tr. 1497-1502). Although the ALJ did acknowledge that the benefit of some advertisements is less clear, he concluded that the record supports a finding that a substantial portion of this program is for media programs beneficial to ratepayers.

> The Staff and the OCA have filed exceptions arguing that the EEI's national media efforts are of a lobbying nature primarily aimed at increasing revenues.
>
> While Duquesne claims ratepayer benefits, both the Staff and the OCA have pointed out some specific instances where media communication programs did not, in our view, effectively benefit Duquesne ratepayers. On balance, we are not satisfied that this expense results in direct benefits to Duquesne ratepayers. Therefore, we shall deny Respondent's claim for $107,000 representing 1982 Media Communciation dues.

The issues here are virtually identical. In view of the Commission's recent decision in this area, the adjustment proposed by Trial Staff and the OCA should be adopted.

4. Advertising Expense

Trial Staff proposes a normalization adjustment to PP&L's test year annual advertising expenses (T.S. St. 9). Trial Staff witness Jones used the historic actual advertising expense for the three prior years, removed the EEI assessment and factored in an annual inflation factor using the reported GNP Implicit Price Deflator for each year so as to equate actual expenditure to 1983 dollars; using this methodology, the Staff witness recommended a normalized allowance of $456,307 (Staff Exhibit 9-A) or a disallowance of $163,000 from the company's claimed $619,000. Trial Staff contends that the historic instability of this expense item warrants such treatment.

PP&L argues that there is no basis for such an adjustment since this estimate is fully supported on the record. PP&L witness Berish testified at considerable length (PP&L St. R-2, pp. 6-8) concerning the reasons for this budgeted increase. Over half of this increase is attributable to PP&L's efforts to promote energy efficiency. The remainder is due to expanded customer education of PP&L's billing practices, nuclear employment advertising, which previously had been capitalized, and information regarding power outages due to storms.

The record shows that this level of expenditures is expected to continue for several years and, as a result, the level of expenses claimed by PP&L is appropriate for use in this proceeding.

5. <u>Recreational Facilities Expense</u>

PP&L is claiming $1,567,986 in O&M expense associated with seven separate recreational facilities (T.S. Exhibit 9-B, Sch. 2, p. 4). Of this amount, $268,746 is for three facilities which are neither owned nor operated pursuant to any specific Federal or state licensing requirement (T.S. St. No. 9 [Supplemental], pp. 1-2).

Trial Staff argues that the operations and maintenance costs of facilities not established pursuant to express licensing requirements are not requisite to the provisions of safe and adequate service and, therefore, should be viewed as charitable contributions, not chargeable to ratepayers.

A similar adjustment was approved by the Commisison in the past and should be made in this proceeding also. <u>Pennsylvania Power & Light Co.</u>, 54 Pa. P.U.C. 645, 664 (1981).

6. <u>EPRI Dues</u>

PP&L has claimed $4,921,000 for contributions to the Electric Power Research Institute (EPRI). EPRI was founded in 1972 by the nation's electric utilities to develop and manage a nationwide cooperative industry research program for improving electric power production, transmission, distribution and utilization. Two adjustments have been proposed to this claim.

OCA witness Cotton recommended that the portion of PP&L's contribution which is attributable to nuclear research activities be capitalized and included in the cost of Susquehanna Unit 2 (OCA St. No. 5, pp. 32-33). As stated by Mr. Cotton:

> Approximately 24% of the EPRI budget is specifically for nuclear research activities. Therefore, the Company test year EPRI claim would include $977,000 for nuclear research activities. To date, the applicability of the nuclear research must be for Susquehanna 1 and for Susquehanna 2. These are the only units PP&L has or has ever had that nuclear research activities could possibly benefit. While Susquehanna 1 is going into service in the future test year, Susquehanna 2 is not. Susquehanna 2 is in CWIP and accruing AFUDC. Because the type of work EPRI does is rather basic fundamental research of a highly technical nature, specific amounts paid EPRI for nuclear research activities cannot be specifically assigned to one of the two units. The $977,000, therefore, should be viewed as a common nuclear expense. Since Susquehanna 2 has been excluded from consideration in this case, I recommend that one-half of the common nuclear expense of $977,000 or $468,000 (Pa.) be excluded from pro forma test year expense (See Schedule 20).

PP&L argues that the sole basis for Mr. Cotton's proposed allocation is his conclusion that ". . . specific amounts paid by EPRI for nuclear research activities cannot be specifically assigned to one of the two units" (OCA St. 5, p. 32). PP&L contends that, in view of the very nature of research, it would be entirely inappropriate to even attempt to do so. For this reason, PP&L, in accordance with the Uniform System of Accounts prescribed by FERC and adopted by this Commission, has classified these costs as administrative and general expense (PP&L St. R-2, pp. 13-14).

Moreover, the company maintains, approximately 90% of the "basic fundamental research" in question involves programs which relate to the operation and not the construction of a nuclear generating unit (PP&L St. R-2, p. 14). Accordingly, even if one were inclined to try to assign research expenditures to specific facilities, it is clear that the vast majority of the work presently being conducted by EPRI is of direct and immediate benefit to the company's current customers. The company's position has merit; the OCA adjustment should not be adopted.

For the first time in its brief, Trial Staff contends that "shareholders should be obligated to shoulder the burden of all EPRI contributions on an equal basis with ratepayers" (T.S. MB, p. 40). Trial Staff argues that if these EPRI expenses are a legitimate cost of doing business and are beneficial to the ratepayers, the Commission should not fail to recognize that they are equally beneficial to the company's shareholders. Trial Staff recommends the Commission allow only half of the claimed EPRI expense and thus require shareholders to assume a one-half share of the cost; this amounts to a $2,460,500 disallowance of the company's EPRI expense claim.

The Trial Staff proposal should be rejected on two grounds. Merits aside, it is highly inappropriate for a party to propose a completely new adjustment for the first time in its brief. Philadelphia Electric Co. (R-811626, Order issued May 21, 1982).,

Additionally, any expenditure which improves the quality of the company's service will, it is to be hoped, generate benefits to both the shareholders and the ratepayers. But this, by itself, does not justify imposing half of the cost on stockholders.

7. Holtwood O & M Expense

OCA witness Cotton proposed a $535,000 downward adjustment to the company's Holtwood Steam and Hydro generating station O&M expense to account, in his view, for the abnormally high level of such expense in the future test year (OCA St. No. 5, pp. 22-23, Sch. 15).

As noted by Mr. Cotton, PP&L's future test year claim for the Holtwood Steam unit was 15.2% above the actual expense in the prior year, while the Holtwood Hydro expense claim was up by 21.7%. Based on discussions with the company, Mr. Cotton testified that the reasons for the increase "ranged from rebuilding the furnace sidewalls to buying a spare parts inventory." Mr. Cotton noted that the company indicated that much of the future test year work at these stations was work that had been put off in prior years and was overdue.

Mr. Cotton recommended that the future test year O&M claim for these stations be normalized to reflect the fact that it contains higher than normal expenses due to make up work which was not performed in prior years. He calculated a normal level of expense by taking the average of the future test year projection and the actual historical data for the last two years. To this average, which in time would be July 31, 1982, he added a 7.5% factor for inflation and wage increases. The adjustment, he stated, thus reflects a normal level of expense at these stations over three years, but is effectively stated in July 31, 1983 dollars.

PP&L argues that any averaging or inflation trend analysis is a poor substitute for a specific budget estimate. The company notes that although such an approach may have some superficial appeal and would unquestionably simplify matters, it would also render the presentation of extensive future test year data a meaningless exercise. Moreover, this type of analysis becomes particularly suspect where, as here, the inquiry is limited to but two of the company's generating facilities which together account for only 7.9% of its total budgeted production plant operating and maintenance expense.

PP&L witness Berish testified (PP&L St. R-2, p. 12) that the work performed at a particular generating station is not a function of the rate of inflation but rather is dictated by the needs of that facility. As a result, the maintenance dollars budgeted for any given plant can and do vary significantly from year to year. PP&L points out that, for example, had Mr. Cotton performed the same calculation with respect to the company's Brunner Island station, he would have derived an inflation-adjusted average maintenance figure of approximately $24.4 million, or some $1.8 million in excess of PP&L's claim (PP&L Exhibit Regs. I-B-2, pp. 1-3).

A similar issue was presented in the recent Duquesne rate case (R-821945, Order issued January 28, 1983). There the Commission apparently adopted the position of the ALJ that consideration be given to the overall level of maintenance expense since the level at each individual plant may vary from year to year. In addition, the Commission appeared to be persuaded there by the fact that actual expenses were running higher than budgeted (mimeo, p. 33).

It should be noted here that during the first eight months of the future test year, total non-energy related operating and maintenance expenses equalled $213,914,000, or $3,271,000 more than the $210,643,000 budgeted by the company for that period (PP&L Exhibit MJB-9C).

The OCA adjustment should be rejected.

8. Tree Trimming Expenses

OCA witness Cotton proposed that the company's claim for tree trimming expenses be reduced by $800,000 (OCA St. No. 5B, Sch. 14, p. 1). In developing his recommended adjustment, Mr. Cotton determined the average number of trees trimmed and removed during the four year period from 1979 to 1982 and applied an average cost per unit to arrive at what he believed to be a "normalized" level of expense for ratemaking purposes (OCA St. No. 5, pp. 20-21).

PP&L argues that historic averages provide little insight into current or future needs.

As noted by PP&L witness Berish (PP&L St. R-2, p. 9), the level of tree and brush control required is largely dependent upon the miles of line which the company must maintain. Since PP&L's transmission and distribution systems steadily expanded during the period reviewed by Mr. Cotton, the volume of work to be performed also increased (PP&L Exhibit 200.182034).

In addition, PP&L maintains, the average figures employed by Mr. Cotton bear no relationship whatsoever to the number of trees trimmed and removed in the recent past. Thus, for example, the company actually trimmed 647,155 trees during the historic test year and 692,097 trees in calendar year 1982, or substantially more than Mr. Cotton's four-year average of 626,636. Similarly, in the case of tree removal, Mr. Cotton's average (161,599) is less than either the comparable historic test year (162,738) or calendar 1982 (179,258) figures (PP&L St. R-2, pp. 9-10). In contrast, when measured against actual calendar 1982 results, the company's claim reflects a small increase (3.8%) in the number of trees removed and a decrease (4.6%) in the number of trees to be trimmed (PP&L St. R-2, pp. 10-11).

Finally, Mr. Berish stated, total tree and brush control expenditures during the first five months of the future test year exceeded PP&L's budget projections by $688,000.

The company's position has merit and the OCA adjustment should be rejected.

9. <u>Amortization of Stony Creek Project</u>

In 1969, the company acquired from the Commonwealth of Pennsylvania's Game Commission title to 1,702.19 acres in the Stony Creek Valley in exchange for certain land owned by PP&L in the nearby Clark Creek and Fishing Creek Valleys. The site was obtained in anticipation of the construction of a pumped storage hydroelectric generating station and the deed by which it was conveyed provided that the land would revert back to the Game Commission if the project were not completed (PP&L Exhibit 175.282015).

In March 1980, Stony Creek was designated a Wild and Scenic River under the Pennsylvania Scenic Rivers Act and the company realized that it would be impossible to obtain the necessary approvals for the construction of a pumped storage facility at that site. Accordingly, on April 27, 1981, PP&L and Metropolitan Edison Company, a joint owner, agreed that the project would be terminated and that the company would arrange to have the land revert back to the Game Commission. This determination was subsequently approved by the company's Board of Directors and title to the property was reconveyed in August 1981 (PP&L Exhibit 175.282015).

In this proceeding, PP&L requested that it be permitted to begin to recover its investment in the Stony Creek project. Specifically, PP&L has proposed that those costs be amortized over a five-year period and that it be allowed to collect $386,000, or $186,000 net of taxes, on an annual basis. A similar claim presented by Metropolitan Edison Company (R-80051196) for its share of the losses associated with this project has previously been approved by the Commission (PP&L St. R-6, p. 36; Tr. 2548-2549).

The OCA opposes this claim on the ground that it allegedly violates Section 1315 of the Public Utility Code (OCA St. No. 5, pp. 24-25). In its brief (OCA M.B., p. 142), it notes that subsequent to Mr. Cotton's testimony, the Commission entered an order upon reconsideration on April 18, 1983, in the CAPCO Investigation (I-79070315), in which the Commission rejected this argument with respect to costs of four cancelled nuclear plants. The OCA notes its disagreement with the CAPCO ruling and its intention to file a Petition for Review of that decision with the Commonwealth Court. As to Stony Creek, the OCA still submits that the statutory language of Section 1315 is controlling and that the requested amortization should be rejected as a matter of law.

On the basis of the Commission's April 18, 1983 ruling, the adjustment must be denied. If Section 1315 permits a utility to recoup its investment in a plant which it voluntarily elects not to complete, it certainly permits a utility to recover its costs when a project is terminated by virtue of action taken by a government agency.

10. Fuel Supply Audit

The Commission has directed that an audit be conducted, under the direction of the Bureau of Audits, of PP&L's fuel supply operations. PP&L has included $347,000 in its test year expenses for this item (Tr. 774).

Trial Staff claims that no payments will be made until after the end of the future test year and, for that reason, the claim should be disallowed (Tr. 1592).

PP&L argues that in the past the Commission has never felt compelled to rigidly adhere to the "test year concept," but rather has properly recognized that known or reasonably anticipated changes must be reflected in fixing rates for the future. It cites Chief Administrative Law Judge William R. Shane in Pa. P.U.C. v. Philadelphia Electric Co., Docket Number R-811719 (Recommended Decision issued April 29, 1982, p. 64), where he stated:

> The parameters of the future test year are not blinders, but handy bounds enclosing most of the needed data whose sole purpose is to make the best possible forecast about just and reasonable rates . . . .
> (emphasis in original)

Here there is no doubt that a management audit will shortly occur and that PP&L will incur substantial expense.

I agree, however, with Trial Staff witness L. B. Jones that due to the non-recurring nature of these charges (Tr. 816), they should be amortized over a five year period (T. S. St. No. 7, p. 6).

11. Forced Outage Reserve Credit

According to Trial Staff, from 1972 through 1980, PP&L was recovering through base rates an annual forced outage reserve allowance which was credited to a reserve account and used to finance the costs of energy purchased during outages of the company's generating plants. In October 1978, PP&L adopted an energy clause but retained the remaining balance in the reserve account indicating that when energy costs exceeded $1 million, the amount of such excess would be charged against the reserve and credited to energy costs recoverable through the energy clause (T.S. Exhibit 10-A, p. 2).

During the course of the Commission's 1981 Section 1307(d) audit, it was learned that in February 1981, PP&L had charged the reserve for the then remaining balance ($5,194,510) and credited Accumulated Deferred Income Taxes and Miscellaneous Nonoperating Income; the consequence of this accounting transaction was that the balance remaining was not passed through to customers, but was instead retained by shareholders (T.S. St. No. 10, p. 2). Trial Staff witness Crawford testified that the $5,194,510 balance should have been returned to ratepayers.

PP&L opposes this adjustment. PP&L established this Major Forced Outage Reserve in 1968 to protect the company and its shareowners from large decreases in reported monthly earnings resulting from a major forced outage at any of the company's large generating stations (PP&L St. R-1a, p. 2). This self-insurance was implemented by monthly charges to expense for the estimated future costs associated with a major forced outage extending beyond a minimum period. When operating units were out of service beyond this minimum period due to accidents or acts of nature, the resulting additional power costs were charged to the operating reserve.

PP&L maintains that from September 1, 1968, when the reserve was established, through March 31, 1972, when it was first specifically recognized in rates, the net accumulated provisions to the Major Forced Outage Reserve were provided solely by the company's shareowners (PP&L St. R-1a, p. 2). As of March 31, 1972, the balance in the reserve provided by the shareowners was $3,709,168 (PP&L St. R-1a, p. 3). If PP&L had not established the Major Forced Outage Reserve, the credits to the reserve would not have been charged to expense, and operating income for the period September 1, 1968 through March 31, 1972 would have increased by $3,709,168. Retained earnings at March 31, 1972 would have increased by the same amount.

PP&L claims that since the balance in the reserve at March 31, 1972 had been provided solely by PP&L's shareowners, a flow-through of those funds to cutomers is not proper or equitable. Moreover, because the $3,709,168 in the reserve at that date was a net balance, shareowners obviously had provided a greater amount during the first four years of the reserve's existence.

In October of 1978, PP&L converted from a fuel clause to an energy clause. Under an energy clause, the costs of major forced outages are collected from customers (PP&L St. R-1a, p. 6). In order to protect customers from sizable increases in the monthly energy clause charge resulting from such outages, PP&L obtained Commission approval to continue provisions to the self-insurance reserve (PP&L St. R-1a, p. 8).

Between March 31, 1972, when the Major Forced Outage Reserve was first specifically recognized in rates and October 31, 1978, when PP&L converted to an energy clause, the company's base rates included the reserve as an accounting procedure to levelize the costs of forced outages. The costs associated with major forced outages during that period were normal utility operating and maintenance expenses.

PP&L argues that any adjustment to fuel costs in the present proceeding to flow-through to customers the balance remaining in the company's Major Forced Outage Reserve as of October 31, 1978 would constitute retroactive ratemaking. PP&L notes that it is well established in Pennsylvania that rates previously approved by the Commission can be changed only prospectively, not retroactively. 66 Pa. C.S. 303; Cheltenham & Abington Sewerage Co. v. Pa. P.U.C., 344 Pa. 66, 25 A.2d 334 (1942) appeal dismissed, 317 U.S. 588 (1942); Metropolitan Edison Co. v. Pa. P.U.C., 66 Pa. Cmwlth, 460, 437 A.2d 76, 79-80 (1981); City of Pittsburgh v. Pa. P.U.C., 45 Pa. Cmwlth. 80, 404 A.2d 786 (1979).

In an Order dated January 30, 1981 at Docket Number R-80031114, the Commission disallowed the company's claim for provisions to the Major Forced Outage Reserve. Accordingly, PP&L maintains it wrote off the reserve to income as recommended by the Federal Energy Regulatory Commission (FERC).

During the period between October 31, 1978, when the company converted to an energy clause, and January 30, 1981, when the Commission disallowed the Major Forced Outage Reserve, the cost of forced outages charged to the reserve and used to reduce energy clause charges was $6,737,401 (PP&L St. R-1a, p. 9). Provisions to the Major Forced Outage Reserve for this same period aggregated only $4,286,000. As a result, charges which could legitimately have been collected from customers under the energy clause were reduced by $2,451,401. PP&L maintains that since the company voluntarily reduced customer charges by this amount, which properly could have been credited to earnings, no adjustment in the present proceeding is appropriate.

Trial Staff's adjustment has no basis in fact or law and should be rejected. It is not only retroactive ratemaking, but also is inconsistent with the position taken by Trial Staff in other cases where a utility seeks to be made whole for underrecoveries of certain expense items. See Philadelphia Electric Co. (R-811626, Order issued May 21, 1982, p. 46). We cannot go back and correct for one single item out of any number of variations between pro forma expenses and actual expenses from prior rate cases.

B. SUSQUEHANNA-RELATED ITEMS

1. Initial Fuel Cycle

As part of its O&M expense claim for Susquehanna Unit 1, PP&L claimed some $934,000 relating to the company's first fuel cycle (T.S. St. 14, pp. 1-2). Trial Staff argues that the specific claimed expense levels are not "annual" or "normal." It argues that the $934,000 total should be amortized over two years.

PP&L claims that these costs are recurring in nature and will be experienced on an annual basis. PP&L witness Kenyon (PP&L St. R-16, pp. 1-2) stated:

> First, the costs identified by Mr. Jones are associated with engineering maintenance support, outage planning and plant staff planning functions, which are expected to be relatively stable during the first year that rates set in this proceeding will be in effect. Secondly, these functions will be continuing over the life of the plant and are necessary for safe and/or economic operation. Additionally, over the next several years the costs of operating and maintaining Susquehanna will be increasing to recognize new facilities to be operated and maintained and Unit 1 refueling expenses not covered by these rates. The generally increasing costs preclude overcollection by PP&L even if rates are not adjusted in the forseeable future. For all of these reasons, I believe that the adjustment proposed by Mr. Jones is unreasonable and unwarranted.

There appears to be no basis in the record for Trial Staff's adjustment and it should be denied.

2. Spent Fuel

PP&L's original claim for the cost of spent fuel disposal was $8,153,000 (PP&L Exhibit Future 1, Sch. D-13). This estimate was effectively mooted by the enactment of the Nuclear Waste Policy Act of 1982. Under that Act, the United States Department of Energy will assess utilities at the rate of one mill per kwh for each kwh generated at a nuclear reactor after April 7, 1983 (OCA St. No. 5, p. 29).

The effect of this revision is to reduce PP&L's claim for spent fuel disposal costs from $8,153,000 to $5,400,000. The claim, as revised, is uncontested.

3. Decommissioning Expense

The company has estimated the cost of decommissioning Susquehanna Unit 1 at $103.1 million and seeks to recover this amount through annual accruals of $2.6 million over a 30-year period (PP&L Exhibit Future 1, p. D-12). PP&L proposes to establish an escrow account for these accruals and to invest the accrual in tax-exempt securities.

The company's claim for decommissioning expense is based on a study prepared by Mr. Albert A. Weinstein, Manager of Engineering of S.M. Stoler Corporation (PP&L St. 16, p. 1). Mr. Weinstein's study was primarily based on a 1980 study by Pacific Northwest Laboratory entitled "Technology Safety and Cost of Decommissioning a Reference Boiling Water Reactor Power Station" ("PNL Study"), which was commissioned by the Nuclear Regulatory Commission. He applied the methodology developed in that study, adjusted for differences in the design of Susquehanna and the PNL reference plant and updated to reflect 1983 prices where available.

Mr. Weinstein estimated the cost of decommissioning Susquehann Unit 1 to be $115.3 million (PP&L St. 16, p. 5). As a check on this result, Mr. Weinstein applied the methodology employed in the actual decommissioning of the Elk River and BONUS plants. This method predicts the cost of Unit 1 decommissioning at $144.2 million (PP&L St. 16, p. 5).

Trial Staff takes issue with the company's computation of total decommissioning costs and with use of the accrual methodology in lieu of an annual annuity which reflects the accumulation of interest on escrow deposits.

Trial Staff witness Pachul developed a decommissioning cost estimate of $54,000,000 for removal of Unit 1 plant. PP&L's cost of removal as estimated by Trial Staff is $48,600,000 ($54,000,000 x .90) (T.S. St. No. 2, p. 7).

PP&L points out two differences between Mr. Pachul's study and its own. The first is his adjustment of the PNL Study from 1978 dollars to 1983 dollars. Mr. Pachul applied the general GNP Price Deflator, while Mr. Weinstein based his estimate on actual 1983 prices where available. Mr. Weinstein argued that Mr. Pachul's approach is without merit (PP&L St. R-10, pp. 2-3):

> This is a fundamentally flawed approach as it is based on the unsupportable assumption that the specific costs of decommissioning a nuclear power plant have increased only at the general rate of inflation since 1978. This is simply not the case. In fact, in the introductory paragraph to Appendix M of the PNL Study the reader is cautioned that "to ensure the applicability of the estimate to any specific situation, the data [unit cost data] should be carefully examined and adjusted as necessary." As set forth in my direct testimony, in several important areas actual price information demonstrates that significant components of the cost of decommissioning a nuclear power plant, e.g., the burial of radioactive waste, transportation of radioactive waste, electric energy and nuclear insurance, have increased at a rate much higher than

> the inflation rate. By simply applying the GNP deflator to these components Mr. Pachul has seriously understated the cost of decommissioning Susquehanna.

This difference in methodology accounts for all but \$6.4 million of the difference in Trial Staff's and PP&L's estimate (PP&L St. R-10, p. 5).

The remaining difference, according to the company, is largely attributable to Mr. Pachul's failure to consider differences in Susquehanna and the reference plant in the PNL Study. As explained by Mr. Weinstein (PP&L St. R-10, pp. 6-7):

> The second fundamental flaw in Mr. Pachul's testimony is his failure to adjust the PNL Study for known differences at the Susquehanna plant. The most significant impact of this error is to drastically understate the transportation cost of low level radioactive waste disposal. The plant in the PNL Study was located in the state of Washington, which also is the location of the only available low level radioactive waste disposal site in the United States. To adjust for this fact, the PNL Study calculated transportation costs based on the assumption of a 1000 mile round trip between the reactor and the disposal site. Since Susquehanna is somewhat over a 5000 mile round trip from the Richland, Washington disposal site, the PNL Study obviously understates transportiona costs for Susquehanna decommissioning. My study reflects this difference in distance, which would add \$3.94 million to transportation costs in the PNL Study.
>
> Mr. Pachul extensively discusses his belief that a Federal waste disposal site will be available in the Eastern United States at some unspecified future date. What Mr. Pachul fails to note is that all of the potential sites he references are for the disposal of <u>high level</u> radioactive wastes. The transportation costs at issue are for <u>low level</u> radioactive wastes. To the best of my knowledge the Federal Government has no plans to construct a low level radioactive waste disposal site in the Eastern United States. Mr. Pachul's argument simply addresses the wrong issue.
>
> Moreover, Mr. Pachul fails to adjust the PNL Study to reflect differences in the design of Susquehanna and the PNL model plant. My study calculates these adjustments, and while they are minor, there is simply no basis for Mr. Pachul's objection to them.

Trial Staff also claims that the company's methodology fails to recognize escrow interest earned over the period of accumulation.

Mr. Pachul, using a 8.5% annual yield on tax exempt securities as estimated by Trial Staff witness O'Donnell (T.S. St. No. 15), calculated an annual annuity requirement of $183,372 based on Trial Staff's decommissioning cost estimate of $53,460,000 (T.S. Exhibit 2-B, p. 2, Pachul). Trial Staff consequently proposed a $2,460,028 downward adjustment to PP&L's $2,644,000 annual accrual claim for decommission expense.

The company claims that this proposal should be rejected.

First, PP&L argues, it fails to reflect any impact for inflation on the ultimate cost of decommissioning in 2023. As explained by Mr. Bernini (PP&L St. R-1, p. 10):

> Exhibit RJB 2 sets forth the annual inflation rate for the period 1973 through 1982. As can be seen, inflation is present in every year and averaged 7.57% for the 10-year period. In my opinion, ignoring the impact of inflation by assuming a zero inflation rate as Staff has done is <u>not</u> a reasonable assumption. The $103,096,000 claimed cost of decommissioning Susquehanna Unit 1 is stated in 1983 dollars. The estimated retirement date for the unit is the year 2023. The actual cost of decommissioning Susquehanna Unit 1 will be in 2023 dollars not 1983 dollars.

Moreover, Mr. Pachul's calculation erroneously fails to recognize that the interest earned on the decommissioning escrow account is not tax deductible (PP&L St. R-1, pp. 10-11).

The company also notes that PP&L's accrual method is identical to that repeatedly approved in recent rate proceedings and should be approved in this proceeding. (<u>Philadelphia Electric Co.</u>, R-811626, Order issued May 21, 1982, mimeo p. 38)

The OCA opposes Mr. Weinstein's addition of a 25% contingency factor to the total cost estimate for decommissioning Susquehanna Unit 1

(PP&L Exhibit AAW-1, Table 3). This adds approximately $453,090 to the company's before-tax jurisdictional test year claim (OCA St. No. 5, pp. 26-28).

I agree with the OCA that this 25% is speculative at this time. As stated by the Massachusetts Department of Public Utilities in rejecting an identical 25% contingency factor for decommissioning costs at the Millstone nuclear units:

> Harry Gildea, an expert witness for the coalition, testified that in his opinion, "it is not appropriate to set rates to recover allowances for contingencies." We agree. The company has failed to demonstrate that the 25 percent is anything but conjecture on its part. While not wanting to suggest that the company's estimate will be immune to cost increases between now and the actual time for decommissioning, we cannot permit the ratepayers to be subject to a contingency factor which is too speculative in nature and which is as likely to fluctuate downward as upward as the state of the art develops. The company, therefore, may not include a contingency factor in calculating decommissioning expenses at this time.

Re Western Massachusetts Electric Co., 37 PUR 4th 219, 229 (Mass. DPU 1980).

Trial Staff's adjustments should be rejected while that proposed by the OCA should be adopted.

4. Deferral of Costs for First Refueling Outage

PP&L estimates that Susquehanna Unit 1 will be taken out of service in the latter part of 1984 for its first refueling (PP&L St. 2, p. 9). It is estimated that this outage will continue for 15 weeks.

The costs of such a refueling outage are over and above the normal level of operating costs for the plant during this period and are expected to approach $15 million here.

PP&L is proposing to spread the cost of the first outage over the period of time from the date Susquehanna Unit 1 is restarted with the second core through the operating period of the second core and through the second refueling outage (PP&L St. 2, p. 10). Since PP&L is proposing to reflect these costs in a period after they are incurred, it is necessary to accumulate and defer the actual costs of the first refueling outage on the company's books and amortize this amount over the period it is recovered in rates. Here, the company has requested formal Commission approval of the accounting procedure described above so that the first refueling outage costs can be deferred on the company's books of account.

PP&L does not want the Commission to adopt an order which establishes future ratemaking treatment for the costs of Susquehanna's first refueling outage (Tr. 850, 852). Rather, it is requesting Commission approval to defer these costs on the company's books and amortize them for book purposes.

PP&L states that it is making this request because it is very unusual to defer and amortize costs for book purposes without Commission approval (Tr. 852-853). Moreover, the Statement of Financial Accounting Standards No. 71 (Dec. 1982), issued by the Financial Accounting Standards Board, indicates that such deferred accounting by a regulated entity is proper only if the regulatory agency has given some assurance that the deferred amount is a valid asset.

In its brief (OCA M.B., pp. 133-134), the OCA opposes this request.

The OCA has no objection to the company's accumulation and deferral of Susquehanna outage costs on its books. The OCA objects, however, to a procedure whereby the company seeks what it terms to be an unnecessary Commission seal of approval on this accounting treatment in advance.

There is no ratemaking approval of these costs here. The company is merely requesting Commission approval to defer these costs on the company's books and amortize them for book purposes. Any future recovery of these expenses will not in any way constitute retroactive ratemaking inasmuch as the rates established in the present case will not be affected by such future recoveries.

PP&L could have claimed a portion of these expenses in the present rate case. It chose not to do so. Such an approach would have produced a claim which Mr. Vanderslice estimated to approximate $9.4 million (PP&L St. 2, p. 9).

The company's request is simply one for approval of an accounting procedure necessitated by this decision not to claim some $9 million in this proceeding. It will have no rate effect here.

The company's request should be approved.

VII. DEPRECIATION

Most of the issues with respect to depreciation of non-Susquehanna plant have been resolved among the parties. The company and Trial Staff have entered into a "Stipulation of Parties with Respect to Certain Depreciation Issues." This document, attached to this decision as Appendix B, contains those parties agreement to:

(i) Continued use of the "PP&L Reserve" and its components, the "True-Up Process" and "Review Process," as it applies to generating plant.

(ii) Approval of all life spans for generating plant as presented.

(iii) Approval of the interim retirement study as presented.

(iv) Approval of the depreciation study as it relates to Hydroelectric Generation, Transmission, Distribution and General Plant.

(v) Approval of the total annual depreciation expense as claimed, exclusive of that related to the Susquehanna Steam Electric Station and contractor retentions.

(vi) Approval of the use of the Book Reserve as the proper reserve to be used in ratemaking for Hydro-electric Generation, Transmission, Distribution and General Plant.

This Stipulation should be adopted.

The remaining issues concern the company's claim for "modified sinking fund" depreciation of Susquehanna Unit 1 and certain depreciation expense adjustments.

A. <u>Modified Sinking Fund</u>

With respect to Susquehanna, PP&L's depreciation expense claim is based on a modified sinking fund approach. Under this proposal, PP&L would employ a sinking fund depreciation method for ten years and then switch to straight-line depreciation for the remainder of Susquehanna's life cycle (PP&L St. 6, p. 20). The primary impact of the company's proposal is to reduce its test year claim for Susquehanna depreciation expense from $42.6 million to $14.8 million, and thereby reduce the rate impact of the addition of Susquehanna Unit 1 to the company's rate base (PP&L St. 6, p. 20).

Dr. Richard Nellis, appearing for the Trial Staff (T.S. St. 11), suggested that the total capital costs for ratemaking purposes be continued at the same fixed amount for about five years longer than proposed until such time as the undepreciated plant balance equaled what it would have been under straight-line depreciation. After this, depreciation would then switch to what it would have been under straight-line with return and depreciation expense calculated in the usual manner (T.S. Exhibit 11A, Sch. 2, p. 2).

As Trial Staff points out, while both the PP&L and its proposals result in a lower capital cost to customers in this proceeding, the Trial Staff proposal results in a lower total cost over the 39-year life of the plant (T.S. Exhibit 11-A, Chart 1, p. 3). Both the Trial Staff and company sinking fund proposals result in a higher total capital cost over the life of the plant than would conventional straight-line depreciation.

It is this effect which has caused Milton Manufacturing to oppose this approach and request use of straight-line depreciation. This, in turn, has been opposed by the OCA which supports the company's position.

Basically, Trial Staff and PP&L are in agreement. PP&L does not oppose Dr. Nellis' proposal, providing several points are clarified. As explained by Mr. Beamer (PP&L St. R-4, pp. 4-5):

(1) A proposal for the treatment of interim additions from the in-service date of Susquehanna Unit #1 to the established cut-over year needs to be developed and implemented into the total depreciation plan of Susquehanna.

(2) An agreement must be reached on whether the cut-over year will be common for all vintages before that year as proposed by PP&L or that the cut-over year will be unique to each vintage as proposed by the Staff.

(3) A proposal for the treatment of interim retirements needs to be developed and agreed upon by the parties concerned.

Q. Please outline what PP&L is proposing regarding the above matters.

A. Basically, PP&L would agree to an extended cut-over year as proposed by Dr. Nellis for Unit 1 or Unit 2. However, PP&L would propose that a common cut-over year be established and adhered to so that the transition to pure life-spanning would take place in one common year.

Q. How would interim additions be treated?

A. A separate depreciation schedule should be required for each new vintage of plant before the cut-over year. These interim additions should be depreciated similarly to the Unit 1 and Unit 2 additions, i.e., depreciated using sinking fund until the cut-over year and then switched to pure life-spanning for the remaining life of the plant.

Q. How would you account for interim retirements?

A. I originally proposed to accumulate them until the cut-over point and then add them to the amount to be recovered over the remaining life of the plant. However, with the extension of the cut-over year, all interim retirements should be treated in a manner similar to those for all power production facilities, i.e., a 5-year rolling average amortization.

Trial Staff has made no proposal in this proceeding regarding the appropriate depreciation of Unit 2 (Tr. 2252). Likewise, it has not proposed that the 12.5% return, used in the calculation of PP&L's SSES Unit 1 capital recovery claim, be applied to this plant in perpetuity (Tr. 2258). Trial Staff's position is that the return granted by the Commission in this proceeding and in succeeding rate proceedings be applied so as to determine the depreciation expense applicable to any given year (Tr. 2258). For these reasons, it cannot agree that the appropriate cut-over year can be identified at this time. If the approved Commission return exceeds 12.5%, the cut-over year would be later than projected (T.S. Exhibit 11-A, Sch. 2) and if the return granted is less than 12.5%, more of the annual amount will be applicable for return of capital and the cross-over period will occur earlier.

Trial Staff takes no issue with PP&L's revised proposal for handling interim retirements (PP&L St. R-4, pp. 4, 5).

Trial Staff's opposition to any final determination of the appropriate depreciation treatment of Unit 2 in this proceeding is correct. We are dealing here simply with Unit 1. Similarly, for the reasons expressed by Trial Staff, no common cut-over year can be established at this time. The company's proposal with respect to interim retirements is adopted.

Milton Manufacturing's proposal would increase PP&L's revenue requirement by $28 million. In view of the magnitude of this rate increase already, such a proposal should not be entertained.

B. Depreciation Expense Adjustment

Trial Staff's adjustment to rate base resulting from contractor reductions would reduce jurisdictional depreciation expense by $17,415. Since the adjustment to rate base was not made, no adjustment to depreciation expense should be made.

Similarly, Trial Staff would disallow $1,334,786 of jurisdictional depreciation expense associated with Susquehanna construction costs and $9,799 associated with audits. Since we have elsewhere rejected these adjustments to rate base, the concommitant adjustments to depreciation should not be made.

VIII. TAXES

PP&L has termed its claim for tax expense as "conservative" noting that, in an effort to minimize the requested rate increase, it elected not to seek normalization of either (1) the Federal and state income tax reductions available under the Class Life Depreciation System (commonly referred to as the Asset Depreciation Range [ADR]) or (2) the state income tax effect of use of the Accelerated Cost Recovery System (ACRS) depreciation method. PP&L's decision to forego these claims in this proceeding reduced the total increase sought by approximately $30.0 million (PP&L Exhibit Future 1, A-1, pp. 2-3).

Several aspects of the company's tax expense presentation have been challenged by the Trial Staff and the Consumer Advocate.

A. Reversal of Deferred Federal Income Taxes

Trial Staff witness William F. Doyle and OCA witness Cotton have each recommended a downward adjustment to the company's tax claim to reflect the amortization of an alleged 2% overcollection of deferred Federal income taxes resulting from the reduction of the corporate income tax rate from 48% to 46% effective January 1, 1979 (T.S. St. 3, pp. 35-36). PP&L has computed its taxes and set up the deferred income tax accounts required by normalization at the Federal tax rate then in effect. Prior to January 1, 1979, PP&L used the allowed 48% rate; when that rate was changed to 46%, PP&L began to normalize at that rate (PP&L St. R-1, p. 4). PP&L seeks here to continue to amortize amounts previously deferred at whatever the prevailing rate is at the time.

Prior to January 1, 1979, the corporate Federal income tax rate was 48%; PP&L and other regulated utilities were during that time collecting income taxes through rates based on the 48% tax rate and were deferring taxes on the same basis. Effective January 1, 1979, the corporate tax rate was changed to 46%. Deferred taxes collected through December 31, 1978 will eventually be repaid at the 46% rate. The difference between deferred taxes collected at the 48% rate and the eventual payment at the 46% rate represents an overcollection of 2% which, of course, should be returned to the ratepayers. This is not disputed. The issue is the time period over which it should be paid back. PP&L would amortize it over the life of the equipment involved. Mr. Doyle recommended that these overcollections be amortized over five years; Mr. Cotton recommended a two-year period.

Commission policy in past rate cases has consistently been to amortize the 2% overcollection back to ratepayers over five years. See, e.g., Duquesne Light Co. (R-821945, January 28, 1983); UGI-Gas Division (R-821899, December 22, 1982).

For the reasons stated in those cases cited above, Trial Staff's adjustments should be adopted.

Under Mr. Doyle's methodology, the amount of the 2% overcollection ($1,060,000) is then divided by five to arrive at the income tax adjustment of $212,000. This reduces revenue requirement by $430,655.

B. Amortization of Investment Tax Credits

The company estimated that its balance sheet at July 31, 1983, the end of the test year in this proceeding, will show the utilization of approximately $110 million of investment tax credits (PP&L St. R-1, p. 7; PP&L Exhibit Future 1, B-1, p. 4). Based upon that figure, PP&L has reflected in its tax expense claim an annual amortization of such credits in the amount of $3,262,000 (PP&L Exhibit Future 1, D-18, p. 3).

Trial Staff witness Doyle and OCA witness Cotton contend that the company has understated the amount to be amortized by $1,844,000 (T.S. St. 3, p. 10; OCA St. 5, pp. 37-38). Specifically, they assert that PP&L erred in failing to reflect any amortization of the investment tax credits claimed in this proceeding as a result of the addition of Susquehanna Unit 1 and have recommended that the company's requested tax expense allowance be reduced accordingly.

Specifically, it is their position that because the Supplement No. 2 rate filing has been submitted on a future test year basis at July 31, 1983, the company's ITC amortization should also be calculated as of that date and thus fails to recognize amortization of ITC's for the years 1979 through 1983 (T.S. St. 3, p. 7).

PP&L justifies exclusion of the more current ITC's on the basis that such amounts are not presently booked. OCA and Trial Staff argue that the company's argument contains a fundamental inconsistency -- calculation of PP&L's tax claim for investment tax credit is based on a prospective basis, i.e., a future test year, and yet the company wishes to amortize the ITC's back to ratepayers on an actual basis. Since PP&L is claiming $113,759,000 of investment tax credits in this case (PP&L Exhibit Future 1, Sch. D-1, p. 1), the parties claim that PP&L is in essence stating that it will utilize such ITC's during the period rates proposed will be in effect and should also be incorporated into PP&L's proposed ITC amortization for the future test year. Instead, these parties point out, the company is not proposing to amortize any of those ITC's back to ratepayers, arguing that such amounts will be included in the ITC amortization calculation only subsequent to their actually being used on a Federal income tax return -- some time in the future after presently available ITC carry forwards have been utilized.

I agree with the Consumer Advocate that on the record here it is incongruous for PP&L to indulge in the fiction that it is paying substantial Federal income taxes at a 46% rate and then deny ratepayers the benefit of any ITC amortization because these credits have not been used on an actual tax basis. Just as the company has provided, for example, a full year of Susquehanna ITC deferral, it should provide for a full year of amortization of this deferral.

Trial Staff's adjustment reduces the amortization associated with the company's $113,759,000 ITC claim so as to include only those assets presently claimed in rate base (T.S. Exhibit 3-A, Sch. 4). Mr. Doyle's ITC adjustment amounts to a $1,844,389 reduction in PP&L's claimed income tax expense (a $3,746,674 reduction to claimed revenue requirement).

C. Oneida Mining Company Tax Loss

Mr. Doyle and Mr. Cotton have proposed that PP&L be required to flow-through to ratepayers the tax benefit of the capital losses generated by the sale of the Oneida Mining Company (T.S. St. 3, pp. 4-6; OCA St. 5, p. 39). A similar recommendation was adopted in PP&L's last fully litigated rate proceeding at Docket Number R-80031114. PP&L continues to believe that this adjustment is incorrect.

In the company's view, the income tax allowance in this case should be based on the level of taxes applicable to utility operations during the test year period. The Oneida investment, the sale of which produced the tax loss in question, was not made by PP&L's ratepayers. Rather, PP&L claims, it was an investment by the company's shareholders who also bore the losses from operation of Oneida while it was owned by PP&L (PP&L Exhibit 200.282235). The capital loss resulting from the sale should not be used to artificially reduce the income tax liability of PP&L's electric operations where it had nothing to do with those operations and where the investment and operating losses were burdens on shareholders, not utility customers.

This issue has been litigated and decided. PP&L did not appeal that prior Commission determination; nor did the company attempt to refute through cross-examination or rebuttal the adjustment when it was offered here.

The amortization previously ordered must be continued and the company's pro forma income tax claim reduced by $525,000.

D. Tax Credit for Increasing Research Activities

Under Section 221 of the Economic Recovery Tax Act of 1981, a 25% tax credit was made available for all "qualifying" research and development expenditures which exceed the level of expense incurred during the preceding base period. The credit is applicable to amounts expended after June 30, 1981 and before January 1, 1986.

The company claims that it did not reflect any such credit in its filing because the Internal Revenue Service had not issued regulations defining "qualifying" research and development or delineating how the credit would be determined. However, at the request of the Consumer Advocate, PP&L developed a very rough estimate of the credit to which it might become entitled for the

1983 calendar year. Based on that response (PP&L Exhibit 200.282234), Mr. Cotton has proposed that the company's tax expense claim in this case be reduced by $129,000 (OCA St. 5B, Sch. 26 Revised).

Mr. Cotton's recommendation should be rejected due to its speculative nature. In the absence of any definitive guidelines, it is impossible at this stage to determine what type of expenditures the IRS would consider as qualifying for the credit. In addition, and as noted by PP&L witness Bernini (Tr. 361-362), the estimate provided by the company most likely overstates the credit which would ultimately be allowed.

IX. DEFERRED SUSQUEHANNA COSTS

A. Background

On May 13, 1982, PP&L filed a petition for Declaratory Order with the Commission, requesting permission to implement certain accounting procedures in anticipation of placing Susquehanna Unit 1 into commercial operation. Specifically, the company's petition sought to establish a mechanism by which to synchronize rate recognition of Susquehanna Unit 1 with that facility's actual commercial operation.

By Order entered July 29, 1982, the Commission approved in part and denied in part the company's petition. The Commission granted the company's request that it be permitted to record as deferred assets and credits the costs and energy savings associated with the operation of Susquehanna Unit 1 from the date of its commercial operation until those costs and related savings were recognized in rates (Order, pp. 6-8). The Commission's Order further provided as follows (Order, p. 8):

> H. In the Company's rate proceeding seeking recognition of any deferred costs, the Commission will address the disposition

of those amounts then recorded as a deferred asset in Account 186 and the energy savings recorded as a deferred credit in Account 253.

As part of its November 22, 1982 filing, the company submitted all of the prepared written statements and exhibits comprising its direct case, including the direct testimony of Mr. George F. Vanderslice (PP&L St. 2). In his written statement, Mr. Vanderslice indicated that the company was, in accordance with the Commission's July 29, 1982 Order, seeking recognition of any deferred costs associated with the commercial operation of Susquehanna Unit 1. Mr. Vanderslice further noted that the magnitude of the company's claim could not be quantified until the in-service date of the Unit was known, but he stated that the necessary data would be provided as the hearing process progressed (PP&L St. 2, p. 31). On March 1, 1983, PP&L submitted additional testimony by Mr. Vanderslice (PP&L St. 18), which set forth the details of the company's proposal for recovery of these deferrals.

Trial Staff and OCA objected to the admission of Statement 18 on the ground that recovery of deferred Susquehanna costs was not an issue properly addressed in this proceeding. The ALJ overruled these objections and refused to certify the question to the Commission. On April 18, 1983, the Commission denied Trial Staff's Petition for Review of Interlocutory Order and affirmed the ALJ's ruling.

We now turn to the merits of the company's claim.

B. The Company's Proposal

The Commission's July 29, 1982 Order permitted the company to record as deferred assets and credits the costs and energy savings associated with the operation of Susquehanna Unit 1 from the beginning of commercial operation until those costs and related savings were recognized in rates (Order, pp. 6-8).

However, the Commission declined to establish a method for amortizing and recovering these deferrals. Rather, the Commission's Order provided as follows (Order, p. 5):

> The parties may address the propriety of recovery, the proper amortization and reasonableness of any deferred costs in the Company's rate case which seeks recognition thereof.

According to the company, the reasonableness of its proposal for recovery of deferred Susquehanna costs cannot be challenged. The present estimate of these costs is $78.6 million, all of which will be expended in providing service to ratepayers. Without approval of its proposal, the company will be unable to recover any of this amount from ratepayers. PP&L maintains that a loss of this magnitude would have a serious impact on the company's earnings' integrity. These deferred costs were reasonably expended to provide service to customers and should be recovered by the company.

Under PP&L's proposal, the basic amount to be deferred would be comprised of carrying charges and deferred operating costs recorded in Account 186, reduced by the deferred energy savings recorded in Account 253 (PP&L St. 18, p. 2). The deferred costs and savings include only those amounts related to PP&L's portion of Susquehanna under PUC jurisdiction (PP&L St. 18, p. 3). This proposal to net deferred costs and deferred savings is reasonable and appropriate. The costs and the savings arise from a single common event - the operation of Susquehanna Unit 1 from the beginning of commercial operation until base rate recognition on August 22, 1983. Any variation in the timing or level of commercial operation will affect both costs and savings. Moreover, it is the incurring of the costs which gives rise to the benefits. Therefore, PP&L maintains, it is appropriate to combine these costs and savings and establish a common recovery mechanism for both.

To this basic net deferred amount would be added an amount equal to the related income taxes on the carrying charge element of the basic deferred amount (PP&L St. 18, p. 4). Because the carrying charges are computed in a manner similar to allowance for funds used during construction (AFUDC), credit is already given for the fact that interest is an allowable tax deduction (PP&L St. 18, p. 5).

A return would be computed on the unamortized deferral that exists at the end of each month starting in the month new rates associated with Susquehanna Unit 1 go into effect and ending when the entire deferral has been fully recovered (PP&L St. 18, p. 5). Throughout the proposed five-year amortization period, the return component would be revised to reflect the latest return allowed PP&L by the PUC.

Because Susquehanna will be in commercial operation before it is recognized in base rates, all of the expenses recorded in Account 186 will have been paid from investor funds, not customer rates. However, the company is proposing to collect these amounts over a five-year period during which time investors do not have use of the unamortized amounts. For this reason, PP&L believes it is appropriate to permit the earning of a return on these amounts until such time as they have been fully amortized.

The precise amount of costs and savings cannot be determined until operation of the deferred accounting mechanism has terminated with rate recognition of Susquehanna Unit 1 on August 22, 1983. Based upon different commercial operation dates, four estimates of such costs and savings were presented in Mr. Vanderslice's Supplemental Direct Testimony (PP&L St. 18).

At the hearing, the company's best estimate is that Susquehanna Unit 1 will be in commercial operation within a few days of May 15, 1983. Thus, it believed the deferred Susquehanna costs are likely to be close to the $78.6 million estimated by Mr. Vanderslice on the basis of a May 15, 1983 commercial operation date (PP&L St. 18, p. 6). Obviously, that date has since turned out to be incorrect. PP&L points out, however, that exact precision is not necessary at this time because under PP&L's proposal all amounts contained in the deferred accounts will be audited by the Commission's Bureau of Audits. Any changes recommended by the Bureau could be incorporated by PP&L into its tariff, or if PP&L did not agree with the recommendations, the matter would be decided by the Commission (PP&L St. 18, p. 8). Under either scenario, it states, PP&L's customers would be fully protected.

Finally, PP&L proposes to recover the amounts enumerated above through a rider added to customers' bills on a KWH basis over a period of approximately five years commencing on April 1, 1984 (PP&L St. 18, p. 6). The rider will terminate when the deferred amounts are fully recovered. PP&L notes that the items being deferred would normally be billed to customers at the time Unit 1 went into commercial operation if the rates were in place to do so (Tr. 1638-1639). Because recovery is being delayed, the deferrals should be collected over a period of years (Tr. 1648). Five years was selected because it is a period of time that the Commission has allowed for amortization in the past.

PP&L seeks recovery of deferred Susquehanna costs through a tariff rider rather than through base rates. This is because recovery of these deferrals will not begin at the time new base rates are set in this case. Under the company's proposal, recovery of these deferrals will extend over five years and the tariff rate necessary for such recovery will be cancelled when the deferred amounts have been totally amortized. Although it is impossible to predict exactly when such recovery will end, PP&L notes that it is unlikely that cancellation of this rate will coincide with the filing of revised base rates. For all of these reasons, it believes that it is more appropriate to recover the deferred amounts through a rider rather than through base rates.

PP&L is proposing that recovery of the deferred Susquehanna costs begin on April 1, 1984. According to the company, that date permits sufficient time for PP&L to submit complete data to the Commission regarding the deferred amounts and a final per KWH charge, for the Bureau of Audits to examine this information, and for the PUC to review the record and issue an order (PP&L St. 18, p. 9). Furthermore, April 1, 1984 is the date when PP&L's rates normally will change as a result of incorporating a new ECR rate into its tariff (PP&L St. 18, p. 9). And finally, it notes, the proposed effective date of April 1, 1984 occurs after the heavy use winter heating season, thereby moderating the first year customer impact of this charge (PP&L St. 18, p. 9).

PP&L also has proposed the following procedure for Commission review of the deferrals. Sixty days after the effective date of new rates recognizing Unit 1, PP&L will file with the Commission a final statement of the costs and savings deferred in accordance with the Commission's July 29, 1982 Order, a computation of the rider charge and a tariff amendment implementing the rider (PP&L St. 18, p. 8). The Commission's Bureau of Audits would review PP&L's filing and within 90 days issue a report on the items contained therein (PP&L St. 18, p. 8). Any change recommended by the Bureau of Audits could be incorporated by PP&L into a revised tariff, or if PP&L did not agree with the recommendations, the matter could be resolved by the Commission (PP&L St. 18, p. 8). After reviewing the Bureau of Audit's report, the Commission would resolve any disputed matters and enter an order allowing the rider to become effective on April 1, 1984 (PP&L St. 18, p. 8).

C. Opposition to the Request

Primary opposition to the company's request comes from Trial Staff and the OCA.

Before beginning an in depth discussion of the arguments presented by Trial Staff, I feel constrained to address what I believe to be a distressing attitude evidenced in its presentation. Trial Staff's briefs are replete with statements to the effect that attrition, if not a positive joy, is nothing about which this Commission should be concerned. For example, Trial Staff states (T.S. R.B., p. 18):

> On page 119 of the Company's main brief, PP&L states that "[t]he items [i.e., "early window" costs] being deferred would normally be billed to customers at the time Unit 1 went into operation if the rates were in place to do so." While this may be literally an accurate statement, it expressly incorporates the highly unrealistic assumption that base rates reflecting Unit 1 would be in place at the moment Unit 1 commercial operation begins. Under such an assumption, the Company's argument avoids confrontation with the basic reality that the lag in base rate recognition simply constitutes attrition <u>for which no ratemaking remedy does or should exist</u>. (Emphasis added.)

Nothing can be further from the truth. The present weakened financial condition of the nation's utilities can be blamed primarily on the ravenous effects of inflation and attrition due in large measure to regulatory lag. Clearly, the Commission itself recognized this in its July 29, 1982 Order where it stated (p. 4) that "[I]nnovative solutions beyond those provided by traditional ratemaking procedures are clearly required" in this situation.

Also disturbing is the apparent position of the OCA that the start-up costs should not be considered in this proceeding since to do so would violate the Public Utility Code. The OCA would oppose the company's claim in any subsequent proceeding as an improper attempt to retroactively recoup expenses. It is apparently the OCA's position that the expenses associated with this plant should be absorbed by the company, while the benefits in the form of lower fuel costs should be flowed through. The equity of the situation is not readily obvious.

According to the OCA, there is no provision, either in Section 1308(d) or any other provision of the Public Utility Code, which permits the company to increase the amount of a general rate increase request beyond the level contained in the original request. Having failed to include this multi-million dollar claim in its original $315 million request, while projecting various other costs of service through the end of the future test year, PP&L cannot remedy that defect by seeking recognition of the costs in this proceeding while deferring the actual calculation and collection of these charges until a later date.

If the company had included a claim for an estimate of its deferred costs at the inception of this case, thus raising its overall claim above the $315 million stated "cap," then recognition of such a claim, and the full accounting detail provided in support thereof, might appropriately have been considered at the same time as the remainder of the general rate increase request. Alternatively, OCA states, the company may seek to include the deferred costs as part of its next general or non-general rate filing and the claim may be considered then (but the OCA would oppose the claim as retroactive ratemaking).

In addition, the OCA argues that PP&L's claim here is contrary to the Commission's prohibition against multi-stage rate relief. The OCA notes that in 1982, the Commission issued a Statement of Policy regarding multi-stage rate filings in which it reviewed the language and legislative history of Section 1308 of the Public Utility Code and concluded that:

> We believe the clear intent of the legislature was to abolish multi-stage rate filings. Therefore, filings for multi-stage rate relief will not be entertained or granted by this Commission, except to the extent permissible under Section 1308(e) of the Public Utility Code.

The OCA argues that here the company is seeking its full general rate increase on August 22, 1983 and seeking permission to implement a second stage supplemental KWH rider in a still unspecified amount to become effective on April 1, 1984. By presenting this multi-stage claim PP&L, according to the OCA, is seeking both to increase the total amount of its original claim, without notifying its ratepayers, and to implement this higher increase in two installments in a manner not permitted by the Public Utility Code.

Finally, the OCA argues that PP&L's proposed claim is contrary to the intent of the Commission's July 29th Order. That Order, by its terms, authorized "a book accounting change only" and was not intended to alter the substantive and procedural rights of the parties to the present proceeding.

Thus, while the Order provides at page 5 that "[t]he parties may address the propriety of recovery, the proper amortization and reasonableness of any deferred costs in the company's rate case which seeks recognition thereof," PP&L has not, according to the OCA, properly sought recognition of those costs in this case. A mere statement of hypothetical future claims in the midst of a general rate case is no substitute for the notice and other statutory requirements for rate increases provided by the Public Utility Code. Having failed to make any claim for these costs in the present rate case, the company must now wait until its next general or non-general rate case to make its claim.

The OCA's review of the ordering paragraphs of the Order finds an apparent intent that the deferred costs not be considered in the same case in which Susquehanna Unit 1 itself is allowed in rates. Thus, Ordering paragraphs G and H are as follows:

> G. Coincident with the effective dates of new base rates recognizing the costs of Unit 1 and of a revised ECR reflecting the effect of Unit 1 on PP&L's energy costs, PP&L will cease recording costs in Account 186 and energy savings in Account 253 as described above.
>
> H. In the company's rate proceeding seeking recognition of any deferred costs, the Commission will address the disposition of those amounts then recorded as a deferred asset in Account 186 and the energy savings recorded as a deferred credit in Account 253.

Since the company will not have "recorded" all of these deferred costs until the date on which base rates from the present rate case go into effect, it is premature, the OCA argues, for the company to seek "recognition" of these costs in the present case.

Trial Staff also argues that approval of the company's claim is contrary to the Commission's July 29th Order, constitutes a multi-stage rate filing and violates the notice provision of Section 1308.

D. Discussion

It is important to note that the issue here is not the actual recovery of these costs but the mechanism for these costs. Not one dollar of the rate increase recommended here will be for these expenses which the company is actually incurring at this time.

My interpretation of the Commission's Order of July 29th comports with that of the company's. The whole thrust of that Order was to establish a system whereby the timing differences between the date of a rate proceeding and the date of the commercial operation of a large generating plant may be minimized. The "next rate proceeding" to which reference is made in that Order obviously refers to this one, not to subsequent filings.[11] In adopting this Order the Commission stated:

> There are numerous advantages to allowing these procedural changes to traditional regulatory practice. It provides assurances that the first nuclear power plant to begin commercial operation in Pennsylvania since the accident at Three Mile Island will be completed and safely tested on a timely basis, unaffected by rate case considerations and pressures, and not rushed into operation to coincide with a rate case. <u>Second, it establishes a procedure which addresses both an early and late contingency and permits PP&L to file a rate proceeding requesting recognition, in the establishing of rates, the costs associated with Susquehanna Unit 1 on a date which helps insure that the unit will, in fact, be in commercial operation before the Commission renders a decision on its used and useful nature</u>. Additionally, it removes Susquehanna Unit 1 from the subjective second-guessing that can occur if some unforeseen event occurs after the rate case is filed. Third, establishing a mechanism for rate recognition of Unit 1 at this time eliminates the procedural and evidentiary conflicts which otherwise might well arise in a future rate proceeding were the issue left unresolved. Finally, it promotes the Petitioner's financial stability and the confidence of the investment community by establishing clear cut procedures for recognizing the rate effect of a major investment, to the mutual benefit of Company and ratepayers. Were we not to act, the potential financial consequences could be dire. Innovative solutions beyond those provided by traditional ratemaking procedures are clearly required. (Emphasis added.)

It would also appear that common sense and administrative economy dictate that PP&L's proposal for recovery of the deferred Susquehanna costs be addressed in this proceeding. Every factor affecting the amount and amortization of these deferred costs has been addressed in this proceeding. A record has been produced on the issues of the construction cost of Susquehanna Unit 1, the proper levels of reserve capacity, reasonable operating

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11/ It should be noted that in the past the Commission has rejected claimed-for extraordinary expense items incurred in the past on the grounds of "remoteness from the test period." If PP&L were to wait until a 1984 test period to claim these expenses, its claim may well suffer the same fate.

and maintenance expenses, depreciation, the proper level of taxes and the required rate of return. The sum of these items will permit determination of the level of deferred costs associated with operation of Susquehanna Unit 1 from its commercial operation date until it is recognized in rates. PP&L witness Vanderslice has been cross-examined by parties on three separate occasions, all relating to the recovery of deferred Susquehanna costs. The record is complete. There is no reason to require a second proceeding to determine the propriety or collection of these items.

The proposed procedure is consistent with Commission practice. PP&L is simply seeking approval of a mechanism for amortization of the deferral. That procedure calls for a subsequent filing by PP&L, review by the PUC Bureau of Audits, and finally review and decision by the Commission itself. Inasmuch as the tariff to collect these costs will not be filed until November 1, 1983, and will not be effective until April 1, 1984, this procedure does not involve the simultaneous filing of rate increases proscribed by the Commission's Regulatory Policy Statement No. 2 on multistage rate filings. See Pa. P.U.C. v. Keystone Water Co. - White Deer District (R-821877, Order issued June 22, 1982).

In addition, the proposed procedure satisfies all notice requirements. Section 1308 of the Public Utility Code (66 Pa. C.S. §1308) requires notice to the Commission and such other notice as it may direct. All active parties in this case have received notice of the company's proposal. Moreover, PP&L's customers will receive notice of the rate change produced by recovery of Susquehanna deferred costs when the company files with the Commission the tariff supplement implementing this deferred cost recovery mechanism. This notice is clearly more than adequate to satisfy due process and 66 Pa. C.S. §1308.

The five year amortization period appears appropriate. The forty year period proposed by some parties would burden two generations of ratepayers with costs incurred for the benefit of current ratepayers while permitting these present ratepayers the full benefit of the fuel savings from this plant.

X. ECR BENEFITS

As the OCA notes, PP&L's $315 million rate increase request actually contains three components: (1) a $101 million increase to recover increased costs unrelated to Susquehanna Unit 1; (2) a $400 million increase to reflect the additional costs of Susquehanna Unit 1; and (3) a $186 million offset to reflect "a reduction in (PP&L's) annual energy costs . . . which is the direct result of the operation of Susquehanna Unit 1" (PP&L Exhibit Future 1, Sch. A-1, p. 2, 8).

PP&L's pro forma revenue schedule and income statement both incorporate this full $186 million in anticipated energy savings, as do the other parties' overall revenue requirement recommendations.

While the $501 million in proposed non-energy related base rate increases would be "locked in" to base rates, the $186 million in pro forma energy savings could be modified on April 1, 1984 when the company's next Energy Cost Rate (ECR) goes into effect. That is, once the plant is allowed in rates, the base rate increase will remain in effect regardless of how Susquehanna operates. The energy savings, however, are only "guaranteed" until April 1, 1984, when, according to PP&L's proposal, any undercollections or overcollections incurred prior to that date will simply be passed through to ratepayers in the next year's ECR.

The OCA argues that the Commission must provide complete assurance to ratepayers that, if a substantial portion of Susquehanna costs are permitted to be included in rates in this case, the energy savings that have also been incorporated in this case will be included as well. If Susquehanna fails to produce the energy savings incorporated in the present case, however, the company should not be permitted simply to make up any deficits -- dollar for dollar -- through the next ECR. If Susquehanna does not operate as well as expected, the OCA argues that the ratepayers should not be deprived of this energy credit through an increase in the ECR. As stated by Dr. Rosen (OCA St. No. 4, pp. 50-51):

> This is only fair from a risk sharing perspective. After all, in such a case, ratepayers would still likely be required to pay depreciation, operation and maintenance expenses and a return to the Company on most of the full cost of the plant. These fixed costs will not diminish, for example, if the plant runs more poorly than has been projected by the Company in the first year. Therefore, the energy savings credited to ratepayers in this case should not be reduced either.

The OCA maintains that during the period the rates from this case will be in effect, ratepayers would be substantially better off if there were no Susquehanna. To the extent, however, that ratepayers are required to pay the high capital costs and expenses associated with the bulk of this plant in present rates, these ratepayers are entitled to an assurance that they will not be deprived of the energy savings that have been incorporated in this case under all parties' recommended revenue requirements.

Trial Staff proposes a similar adjustment (T. S. St. No. 16).

Quite naturally the company opposes this adjustment. PP&L maintains that while it expects the addition of Susquehanna to provide $106 million of additional annual direct fuel savings and $80 million of additional annual "split savings" from sales on the PJM Interconnection, the actual energy savings could be greater or less than $186 million depending on a variety of actors. Any difference in the actual figures should be flowed-through to or recovered from ratepayers as part of the company's Energy Cost Rate for the period April 1, 1984 - March 31, 1985. However, it notes, for purposes of this rate proceeding the $186 million figure is fixed. To accomplish this result the company proposed that its ECR be set at zero concurrent with the effective date of rates set in this proceeding, and asked that the Commission approve this procedure in its final Order.

It argues that the proposals requiring PP&L to guarantee the projected $186 million energy savings are without merit for several reasons. First, these proposals are simply derivative of opposing parties' "excess capacity" adjustments. Moreover, under these proposals PP&L would be required to guarantee any shortfall from the $186 million, but would not receive the savings in excess of $186 million. Finally, this Commission has never guaranteed that PP&L will achieve the return on equity approved by the Commission, or that PP&L's expenses will not exceed the level found to be reasonable by the Commission on a pro forma test year basis. Therefore, it would be grossly inequitable and inconsistent to require PP&L to guarantee that its projection of Susquehanna energy savings will be exactly correct.

The OCA's proposal, with some modification, should be adopted. First, quite simply, at this time there is excess capacity on the PP&L system and current ratepayers would be better off without the plant. They should not be deprived of the anticipated energy savings from this plant.

The company is correct, however, that under the OCA proposal, it would be required to guarantee any shortfall from the $186 million, but not receive the savings in excess of that amount. The Commission should adopt the approach recommended by Trial Staff witness Kalbarczyk that the company be permitted to retain one-half of any profits in excess of $186,000,000 as "shareholder equity."

In summary, ratepayers should not be required to bear all the risks of providing the operating costs for Susquehanna Unit No. 1 plus pay a full return to the company for its investment in this plant, which is a major contributor to the company's excess capacity. The OCA proposal, as modified, provides an equitable resolution of this issue.

XI. RATE STRUCTURE

In addition to the controversy concerning the Susquehanna plant, the parties spent considerable effort litigating the issue of how any rate increase should be distributed among the various classes of customers.

Supplement No. 2 to Electric Tariff No. 199 results in an overall average increase in rates of approximately 25%. This supplement would result in increases to all classes of customers except to the RTS rate class.[12/] The effect of these various proposed changes will be examined in detail below.

The company also proposes a new tariff rule 9F whereby it may institute a trended billing procedure for customers on the Budget Billing Program following a PUC approved rate change. This procedure would phase in the requested increase on customers' bills over a period of time. Since the full amount of the increase is not being paid during this phase-in period, an increase in debit balance for the account will occur. The company proposes that the settlement of this debit balance associated with the procedure be made by December 1984. Trended billing procedure would be available to all customers eligible for budget billing, except temporary, seasonal or speculative

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12/ Rate Schedule RTS is a time-of-day residential service rate with load management capability.

service. PP&L also proposes that customer election of the trended billing procedure automatically place the customer into the budget billing plan upon which the trended billing is based (PP&L Exhibit AJB-4, Appendix E).

The company also proposed to decrease the base cost of energy from 14.11 mills per kwh to 9.683 mills per kwh reflecting a net decrease in energy costs.

A. Summary of Proposed Rate Changes

PP&L proposes to increase general residential service rates by 24.91%. The minimum monthly charge for general residential customers would be increased from $3.77 per month to $4.75 per month. With respect to separate water heating service customers, the company proposes to increase the rate from $4.50 per month plus 2.1028 cents per kwh for all kwh use to $4.50 per month plus 2.8 cents per kwh. PP&L also proposes to eliminate the 80 gallon minimum tank size and proposes to require that the customer provide and install any control device specified by the company. PP&L would allow the customer to select any consecutive 12 hours starting and ending on the hour, between 7:00 p.m. and 9:00 a.m. local time, Mondays to Fridays and all days Saturdays and Sundays, when the water heating service would be available.

Rate Schedule RTD (formerly [RX(R)]) is for single phase residential service metered and billed to recognize time-of-day use. PP&L proposed changes which would eliminate the experimental nature of the existing rate and add a demand provision to the Net Monthly Rate. Existing customers would be exempt from the demand charge for the duration of the 24 month study period ending May 1, 1984. PP&L also proposed to change the application provisions so as to exclude farm use and would allow the customer to select any 12 consecutive hours, starting and ending on the hour, between 7:00 a.m. and 9:00 p.m. local time, Mondays to Fridays inclusive, as the on-peak period for billing purposes. The on-peak period would exclude major holidays.

Rate Schedule RTS is a time-of-day residential service rate with load management capability. The rate has been designed so as to offer significant financial incentive to those customers choosing to install electric space and water heating with thermal storage capability. The major modifications proposed by the company in this rate include changing the application provision to allow the operation of any thermal storage system for space heating or water heating, which is acceptable to PP&L as being effective in limiting on-peak use of electric service. As with the other rate schedules, PP&L would allow the customer to select any consecutive 12 hours, starting and ending on the hour, between 7:00 a.m. and 9:00 p.m. local time, Mondays to Fridays inclusive, as the on-peak period for billing purposes. The on-peak period would exclude the major holidays. The proposed new rate results in a decrease to all customers supplied under this rate schedule. The revenue effect of this proposed new rate for the RTS customer is an estimated decrease of $119.00 per year.

Rate Schedule GS-1 is for small general service at secondary voltage or at a higher voltage at the option of the customer. The proposed new GS-1 rate results in an increase of 25.40% to all customers supplied under this rate schedule. The company proposes to increase the initial rate from $5.00 plus 4 kw and 1.27 per kw to $6.50 plus 1.70 per kw for all billing kw in excess of 4 kw.

Rate Schedule TS(R) is for traffic signal lighting service to cities, boroughs and townships. The net monthly rate for service under this schedule is proposed to be increased from 5.61 cents to 7.3 cents per watt of connected load. The total revenue effect of this increase would be 23.82%.

PP&L proposes various increases in the large general service rate schedules. The proposed percentage increases average 25.32% for GS-3, 25.40% for LP-4, 24.76% for LP-5 and 25.57% for LP-6.

The average increase to all street lighting rates is approximately 21.77% under the company's proposal. The proposed increase for area lights is approximately 21.94%. PP&L recognizes that its proposed increase for the street lighting rate class is slightly lower than that for the other rate classes. According to the company, this lower level of increase is in recognition of the relationship of the street lighting rate class rate of return to the overall company rate of return.

The company has taken the position that due to the magnitude of its requested increase the allocation of that increase to the various rate classes should be on a fairly uniform basis.

B. PP&l's Cost of Service Study

PP&L presented two cost allocation studies. One (PP&L Exhibit AJB-2) covered the historic period ended July 31, 1982. PP&L also presented a study covering the present and proposed rate levels for the future test period, i.e., the year ending July 31, 1983 (PP&L Exhibit AJB-3). It is this latter exhibit which formed the basis for the present investigation. It should be noted at this point that the Commission in PP&L's past rate case at R-80031114 provided that future retail rate filings by that company should be on a Pennsylvania jurisdictional basis only. The studies presented, therefore, provide the allocation of system costs between the Federal and Pennsylvania jurisdictions and the allocations of the Pennsylvania jurisdiction costs so developed to the retail customer class.

The company's total cost of service is made up of the following components: (1) operation and maintenance expenses; (2) depreciation expense;

(3) taxes including income taxes; and (4) return on net investment. Through a cost allocation study, total PP&L costs were assigned to residential, commercial, industrial, and other identifiable customer groups. By comparing costs to serve any customer group with that group's rate revenues the company can measure the return of that group. By relating that return to the allocated rate base for that group, a rate of return is arrived at which can be compared with the system average return and the return of other classes of customers.

Overall costs of service are assigned to groups of customers on the basis of their service characteristics; the principal such characteristic is the voltage level at which the electric supplied is rendered. PP&L's investment and other operating costs have been broken down and assembled into functional voltage level components:

(1) production and high voltage transmission, which is involved in the service to all customer classes;

(2) 138 kv and 66 kv transmission, from which large power customers (rate schedules LP-5 and LP-6) and certain resale customers are directly served, and which are also involved in service to all other classes at lower voltages as well;

(3) 23 kv and 12 kv primary system, from which large general service customers (rate schedule LP-4) and certain other resale customers are directly served, and which is involved in the service to other customers at lower voltages; and

(4) secondary distribtion system, from which street lighting, general service, commercial space heating, and residential customers are served.

PP&L's records are kept in accordance with the Uniform System of Accounts. Since the system of accounts does not identify the costs in precisely functional categoric groupings required for allocation purposes, substantial rearrangement of book data must first be accomplished in order to complete this study. Included in this process are the identification of investment in transmission facilities having a production and transmission function; the separation of distribution facilities between primary and secondary and the latter between investment considered customer-related and that considered demand-related; the assignment of operation and maintenance expenses to categories comparable to plant investment assignments; and the assignment of production expenses to demand and energy components.

The four basic classification criteria for determining the share of component costs chargeable to particular customer groups are:

(1) Relative Demand Responsibility - Since a major factor governing plant investment is the necessity to provide capacity sufficient to be able to meet reliably the combined demand of all customers, investment and other costs considered demand-related are allocated on the basis of the pro rata demand responsibilities of the classes.

(2) Customer Costs - Since a substantial portion of system costs is not related to the amount of service provided, i.e., meter investment, meter reading and customer accounts costs, such costs are allocated on a basis of the respective numbers of customers in each class making up the total.

(3) Energy Use - Since fuel expense is directly related to the amount of energy used by customers, it is allocated on the basis of such use by customer classes.

(4) Direct Assignment - In a few cases the Uniform System of Accounts makes a specific identification of costs which permits assignment directly to the rate class or customer responsible.

PP&L allocates production, transmission and primary demand-related costs on the basis of the monthly peak responsibility method. Under this method, a class' responsibility is the relationship of the average of its 12 monthly contributions to system peak to the average of such monthly system peaks. According to the company, at the secondary level (distribution system below 12 kv) significant diversity of demand does not exist. Therefore, it states, it allocated secondary demand-related costs by the relationship of a class' maximum annual non-coincident peak to the sum of the maximum annual non-coincident peaks of all classes sharing such costs.

PP&L's cost of service study shows that at present rate levels, total Pennsylvania jurisictional rates produce an 8.66% rate of return. Class RS produces a 7.80% return or 90% of the system average. Rate GS-1 produces a 9.8% return or 113.1% of the system average; GS-3 produces a 117.8% return of the system average and LP-4 produces 103.9% of the system average. Rate LP-5 produces a 8.30% return or 95.8% of the system average while LP-6 produces a 9.04% return or 104.4% of the system average. Rate GH produces a 6.89% return, 79.5% of the system average, while street area lighting produces a 13.25% return or 153% of the system average.

Under the company's proposed rates, residential customers will provide a return 92.5% of the system average while small general service customers' return would be 110% of the system average and large general service customers would produce a return 113.8% of the system average. LP-4 customers would produce a return of 102.8% of the system average while LP-5 customers' return would be 94.9% of the system average.[13/] LP-6 customers would produce a return of 105.7% of the system average while commercial heating customers' return would be 80.5% of the system average. Street lighting customers would produce a return of 145.5% of the system average. The company's cost of service study has been severely criticized by several parties as detailed below.

13/ This would be the only class whose relationship of class return to the system return would be reduced under the proposed rates.

C. Commission Prosecutory Staff's Position

The Trial Staff concerned itself with PP&L's proposed pricing in the design of rates LP-4, LP-5 and LP-6 and the allocation of the requested increase among the rate schedules (T.S. St. No. 5). In addition, an alternative rate design for class GS-3 was presented. Trial Staff witness Robert Rosenthal noted that rates LP-4, LP-5 and LP-6 block energy charges based upon hours use of billing demand at the first 150 hours use, next 100 hours use and in excess of 250 hours use. A single demand charge is used in LP-6 while two billing demand blocks are used in LP-5 and LP-4. Under the company's proposal, the energy blocks have received increases substantially higher than the demand blocks. Trial Staff notes that PP&L is concurrently proposing additions to demand-related production facilities of 123% and decreases in base energy cost of 30%. It appears to Staff that PP&L has made no attempt to recognize this fundamental change in cost occurrence through its rate design proposal. Mr. Rosenthal examined PP&L's unit costs for energy, demand and customer related items of service based upon system rate of return for the purpose of rate design. He used a procedure employed by the Philadelphia Electric Company in designing their General Service rates which the Commission has previously approved. This method uses unit cost and load data to convert the expression of costs to a dollars per kw throughout the full range of hours use of a kw demand. Mr. Rosenthal used the same coincidence factor as PP&L only for one portion of the cost analysis. He combined the data from LP-4, LP-5 and LP-6 to develop a new set of coincidence factors/load factor combinations. Use of the combined set, he stated, tended to improve the transition and continuity between the LP rates. In addition, since Philadelphia Electric's approved method uses the BARY curve as the standard for developing its coincidence factor/load factor relationships, he also examined the cost using those factors. He then examined the slopes of the cost curve from zero to 219 hours use, 109 to 292 hours use and 219 to 730 hours use. His proposed rates, however, did not use the energy crisis that his cost analysis supports since use of those prices would have produced rate increases for certain customers which were excessive when compared to the average increase to the rate class.

Mr. Rosenthal noted that the company's revenue request distribution would have moved all major rate groups slightly closer to system average rate of return except for LP-5 and LP-6 which moved away from the system average rate of return. Additionally, he noted, street lighting, commercial heating and GS-3, while moving closer to a system average return, still exhibited significant departures from that average rate of return. He disagreed with use of the 12 monthly peak contribution method for allocating production, transmission and primary demand related costs among rate classes. Mr. Rosenthal stated that this 12 monthly peak contribution method bears little resemblance to how a customer class uses the system. He stated that reflection of class use of the system is better accomplished by employing the average and excess method which is based upon the integration of the kilowatt-hour consumption with the maximum demand of the class. These two components, he went on, which also comprise the load factor of the class, reflect the extent to which a class uses the system and the benefits each class receives from having the system in place. The twelve-monthly peak contribution method does not reflect the usage by customer class and only by happenstance would it reflect the maximum demand of a particular class. Moreover, he stated, this Commission has never approved the use of monthly peak contribution for primary distribution of demand-related costs. Primary distribution is normally allocated by class maximum demands or non-coincident demands, since the size and type of investment, and amount of expenses, are a function of local peak loads and not the system peaks as a whole.

Mr. Rosenthal criticized PP&L's cost allocation study using the average and excess method for the demand allocation of production plant. He stated that the company's development of the allocator was incorrect. According to the Trial Staff, in developing the allocator, the company adjusted the excess portion to the level of the monthly average peak, rather than the level of annual system peak which is the normal procedure.

According to Mr. Rosenthal, rate LP-6 has been assigned by PP&L an excessive rate increase which has caused it to move away from the system average return. The rates for GS-1 and GS-3, as proposed, produce returns which generally are substantially in excess of the system return. Rates for GH and RS, as proposed, produce returns substantially below the system return. In the Schedule 14 of Trial Staff Exhibit 5A, Mr. Rosenthal adjusted PP&L's increase by cost of service rate group. Under this proposal residential customers would receive a 26.2 % increase, GS-1 an increase of 23.1%, GS-3 23.7%, LP-4 25.2%, LP-5 24.5%, LP-6 23.3%, GH 30.1%, and street lighting 22.1%. This, of course, is based on the company's receiving the full amount requested.

Dr. James Giordano of the Commission's Prosecutory Staff also presented testimony which, he claimed, demonstrates that PP&L has not adequately designed rate GS-3. He presented an alternative design for GS-3 which he believes should be approved by the Commission. This rate class applies to large commercial or general service customers at secondary voltage although, at the customer's request, it could be served at a higher voltage. GS-3 is presently a combination rate with a 2-block charge and 3-block hours of use energy charge.

Dr. Giordano noted that PP&L proposes an increase of approximately 27% in both of the two demand blocks and an increase ranging between 36.5% and 39.4% for the three energy blocks. Dr. Giordano believed this to be inappropriate because it is not reflective of the demand and energy costs which GS-3 customers place on the system. Dr. Giordano noted that as with all customer classes PP&L incurs a demand cost, an energy cost, and a customer cost to serve GS-3 customers. Dr. Giordano believes that GS-3 rates must be redesigned to recognize PP&L's increase in demand cost due primarily to the introduction of Susquehanna Unit No. 1 in rate base. Since the proposed class rate of return is 113% of the proposed system return, the demand cost component is higher at that rate. Under the proposed class rate of return PP&L would need to collect approximately $196,000,000 in base rates from its GS-3 customers. However, according to Dr. Giordano, this higher return could entail a subsidy from GS-3 customers to other customer classes. To avoid this result, Dr. Giordano suggests that the company's revenue requirement be based on a total demand cost which collects no more than the overall system rate of return (12.71%) from GS-3 customers. This amount is approximately $175,000,000. This total demand cost expressed on a per unit or kw basis would be $13.63.

With respect to energy costs, Dr. Giordano also recommends using the system wide return on original costs in computing the GS-3 class contribution. Given the various cost of service components, Dr. Giordano advocated a rate for GS-3 customers which would, in the energy blocks, reflect the marginal costs of production. Using these marginal cost estimates as guidelines, he recommended that 6¢, 4¢ and 3.3¢ per kwh be approved by the Commission as the energy charge for the three successive blocks. With respect to the two demand blocks, he recommended a price of $7.35 per kw for the first 125 kw of billing demand and $4.68 per kw for all additional kw. The revenue produced by his rates would be virtually identical with the company's claim.

Dr. Giordano stated that this proposal permits more GS-3 dollars to be collected up front, that is in the demand charges, and in the first energy blocks. This means that PP&L will have to rely much less heavily on the tail block in order to achieve its revenue requirement and its rate of return from this customer class. In other words, Dr. Giordano stated, this proposal puts PP&L in a less risky position.

D. OCA's Position

The Office of Consumer Advocate presented as its primary rate structure witness Mr. Bruce R. Oliver (OCA St. No. 2). Mr. Oliver generally agreed with the company on the major factors which should be considered in the allocation of bulk power facilities costs. He believed, however, that there are methods which would more directly reflect those considerations, although, he noted, the results of the method which he recommended for allocating these costs would not be dramatically different from that offered by the company for residential customers. The results, however, would be substantially different for other classes. Mr. Oliver also criticized the use of class contributions to winter peak demands for the purpose of allocating bulk power supply plant and expenses as not reflective of PP&L's patterns of cost occurrence. He also felt that PP&L's proposed distribution system cost functionalization and allocations result in a substantial overstatement of residential customer cost responsibility in this area and that PP&L's customer account expense allocation substantially understates the cost responsibility of large power customers. He proposed that PP&L's distribution of the revenue increase be modified to reduce the revenue responsibility of the GS-1 class and to increase those of the GH and large power classes. He also felt that the company's proposal to increase the customer charge for schedule RS customers was inappropriate.

As noted above, PP&L uses an average of class contributions to 12 monthly coincident peaks in allocating bulk power supply facility costs. Mr. Oliver noted that the company's choice of this method was made in an attempt to recognize a combination of cost consideration: maintenance scheduling of generating equipment throughout the year as influenced by the PJM load considerations; PJM interconnection installed capacity obligations; recognition of seasonal class diversities; long term stability; and equity. Mr. Oliver recommended use of a "peak and average" methodology to allocate those costs. Under the peak and average method, the portion of the company's bulk power supply facilities costs associated with meeting average demand requirements throughout the year is allocated among customer classes on the basis of an average demand (or energy) measure. The remaining portion of these costs (those facilities required to meet variations in load above average levels) would be distributed among the customer classes on the basis of their proportionate contribution to the company's requirements for generation and transmission facilities to meet its peaks.

Mr. Oliver proposed the use of the peak and average method because he believed more explicit recognition of the factors cited by the company for its choice of demand allocator is necessary. He also believed that the method he proposed provided a more proper functionalization of bulk power facilities costs and a more accurate depiction of class cost responsibilities. He stated that there were two substantial differences between his method and that proposed by the company. First, his approach provided for a more explicit consideration and identification of that portion of bulk power supply facilities costs which is incurred by PP&L to meet energy requirements throughout the year. According to Mr. Oliver, PP&L's investments in bulk power supply facilites are reflective of a combined consideration of energy and demand requirements. If, for example, the company perceived its generation needs to consist only of requirements for additional capacity during the hour of system peak demand, it could satisfy those requirements either by adding combustion turbines or by paying capacity deficiency payments to PJM. New base load generating facilities, such as Susquehanna Unit No. 1, may cost in the range of $1,600 per kw. The former methods of meeting this demand would be considerably cheaper. Thus, he believed, the investment costs incurred by PP&L in excess of the cost of combustion turbine capacity are necessarily energy-related, and they should be allocated within the cost of service study on a basis which is consistent with the manner in which they are incurred.

In addition, the measures of class contributions to peak requirements which he recommends are, he claims, more directly reflective of the methods used by PP&L to determine its own capacity needs. Mr. Oliver stated that the company's participation in the PJM power pool has a major influence on its generation and transmission planning activities. PP&L derives substantial benefits as a result of the diversity of its own system peak with that of the PJM pool, and the proper allocation of those benefits among customer classes can only be accomplished through allocation methods which consider class contribution to the system's diversity from the rest of the PJM pool. According to Mr. Oliver, his allocation method includes explicit consideration of class contributions to system diversity benefits while the company's use of the 12 monthly peak method is less precise.

Mr. Oliver stated that PP&L's current diversity with PJM peak allows it to maintain substantially lower capacity reserves at the time of its own system peak than it would need to maintain if the company operated as a stand-alone system. The determination of capacity obligations for PJM members is explicitly structured to reduce reserve capacity requirements for all participating utility systems by taking advantage of the diversity among their various peaks.

Allocations of bulk power supply facility costs which are based solely on winter coincident demand measures implicitly assume that PP&L must build sufficient capacity to meet all capacity requirements associated with its native system peak, including reserve capacity requirements, from its own facilities. In other words, capacity cost allocations premised only on winter coincident peak contributions assume that PP&L operates as a stand-alone utility.

Schedule BRO-1 to OCA Statement No. 2 provides the results of PP&L's cost allocations at present rates modified to reflect Mr. Oliver's method of allocating bulk power facilities costs. A comparison of this exhibit with PP&L's Exhibit AJB-3 indicates that the rates of return for the RS, GS-1, and GH classes rise while those for other classes decline.

Mr. Oliver believed that PP&L's functionalization and allocation of distribution system costs leads to an overstatement of residential customer cost responsibilities. First, he stated, PP&L's study does not recognize the energy component of primary and secondary distribution facilities costs. Secondly, PP&L's division of costs between its primary and secondary systems is in need of further evidentiary support. Third, PP&L's proposed allocation of the demand-related proportion of services double counts the demands of smaller customers whose maximum requirements would be satisfied by the installation of the minimum size of service defined by the company.

Mr. Oliver did not agree with PP&L that all distribution facilities are either customer-related or demand-related. Instead, he believes, that distribution facilities provide an important energy-related function by supplying local consumption requirements throughout the year. Mr. Oliver concluded that the demand-related portion of distribution system consists only of those facilities which are necessary to meet variation in load requirements over the course of a year.

Mr. Oliver also found that the customer-related portion of the distribution system is contained wholly within the services portion of distribution facilities. While primary and secondary facilities may occasionally serve only a single customer, they are sized to meet the expected requirements of other customers who may later locate in the same area. For primary and secondary lines and for transformers, there are no significant customer-related elements. Thus, according to Mr. Oliver, it should be clear that primary and secondary distribution facilities are sized to meet expected loads within a given locale, not the requirements of the individual customer.

The witness recommended a functionalization of the costs for primary and secondary distribution facilities and to demand and energy components. The base portion of primary and secondary facilities, which is necessary to meet average demand requirements, is categorized as energy-related. The remaining portion of those facilities, which provide the capacity to meet variation load requirements above the average demand level, are identified as demand-related. Schedule BRO-2 to OCA Statement No. 2 shows the effects of Mr. Oliver's proposal on PP&L's customer class cost allocations at present rates. This schedule shows reduction in the relative rate of return for GS-3, GH and SL classes, while the RS and GS-1 classes' rate of return increase. Since this change in allocations only affects distribution system requirements, the rates of return for LP-4, LP-5 and LP-6 customers remain unchanged.

Mr. Oliver also questioned PP&L's separation of primary and secondary overhead and underground distribution facilities. He noted that for overhead distribution plant the company relied upon a 1973 analysis of the portions of overhead distribution facilities which comprised its primary distribution plant. Mr. Oliver argues that the company's reliance on these 1973 factors implicity assumes that the relationship of primary overhead facilities to total overhead facilities has not changed during the ten year period. His assumption, he claims, is contrary to the known identical changes which have been and are taking place in the composition of overhead distribution plants due to the Commission's Order in ID 99 requiring that all new distribution lines for residential developments of five units or more should be installed underground.

In light of the company's changes regarding the installation of distribution lines for residential service which have occurred as a result of the Commission's Order at ID 99, Mr. Oliver recommended that the Commission direct the company to produce a new analysis of overhead distribution facilities costs. Mr. Oliver also maintained that the company's assignment of 10% of the costs for underground distribution facilities to LP-4 customers is not supported by any evidentiary basis.

Mr. Oliver also maintained that the company's allocation of the cost of distribution services is deficient in two areas. First, the company's separation of these costs into customer and demand components is purely judgmental and not based on any study or analysis. Secondly, he maintained that PP&L's allocation of the demand-related component of distribtution services is based on an inappropriate measure of customer class demand. He states that PP&L indicates that its customer-related portion of services is representative of minimum system requirements. According to Mr. Oliver, the minimum size service on the PP&L system can potentially supply the customer demand of approximately 20 kilowatts, but the company's residential load research findings indicate that the average peak day demand per customer is well below that 20 kilowatt level. Thus, he maintains, it is reasonable to conclude that residential customers make little, if any, contribution to the demand-related portion of services cost. In spite of this, PP&L allocates nearly 50% of the demand-related portion of services cost to the residential class. This is because the demand-related portion of services is allocated on total class demand at secondary services level. That measure, Mr. Oliver maintains, fails to net out the demands of customers which would be satisfied by minimum size service installation. If a customer's maximum demands can be met by minimum size service installation, he makes no contribution to the demand-related portion of services cost. Since the vast majority of RS and GS-1 customers have maximum demands substantially below the 20 kw level, adjustment of the company demand allocator for secondary services would result in a substantially different distribution of these costs among customer classes. GS-3 and GH customer groups, which have significantly higher average demand per customer, would carry the majority of the responsibility for the demand-related portion of services cost.

Mr. Oliver, however, admitted that he did not compute the result of a revised allocation of distribution services cost because he has not been able to develop sufficient data to produce a reliable study of the excess demand of RS and GS-1 customers. Secondly, PP&L has suggested that under certain conditions the capability of the minimum service may be 14 kva rather than the 20 kva previously computed. Mr. Oliver recommended that the Commission require PP&L to resolve the question which he has raised and to reallocate the demand portion of services in the next case in a matter consistent with his recommendations.

Mr. Oliver also found that the data used by PP&L in his allocation of meter cost is outdated and the use of this data results in an overstatement of residential class meter cost responsibility.

Mr. Oliver also reviewed PP&L's allocation of customer account expenses. According to his conclusion, PP&L's allocation of this factor understates the cost responsibility of large power customers. He supports this finding in three ways: First, a comparison of uncollectible accounts write-offs for the past three years provided PP&L Exhibit 200.282120 in the allocations of Customer Accounts-Other Expenses in PP&L's Exhibit AJB-2 and AJB-3 demonstrates, according to the witness, that the allocated cost responsibility of large power customers in the area of customer account expenses is substantially overstated. For example, line 3 of pages 44 and 45, section 3, PP&L Exhibit AJB-2, indicates that the total allocated Customer Accounts - Other Expenses for LP-4, LP-5 and LP-6 customers is $24,000. Similarly, line 23, pages 46 and 47, section 3, PP&L Exhibit AJB-3, shows a total allocation of Customer Accounts - Other Expenses for LP-4, LP-5 and LP-6 customers of only $28,000. The allocated dollars, however, are substantially smaller than just the uncollectible accounts write-offs for large power customers in any of the last three years. For example, he went on, PP&L Exhibit 200.282120 shows that uncollectible accounts write-offs for large power customers for the 12 months ended July 31, 1982 were $312,000.

The second basis for his finding is in the development of the expense per customer figures used by PP&L on page 9, section B, of both PP&L Exhibits AJB-2 and AJB-3 to allocate Customer Accounts - Other Expenses among customer classes. For LP-5 and LP-6 customers, PP&L bases its allocation of Customer Accounts - Other Expenses on an estimated expense per customer of $77.00 per year. This $77.00 figure, however, includes no reference to uncollectible accounts expense costs. Thus, Mr. Oliver maintains, the company has explicitly assumed a zero allocation of uncollectible accounts expenses for large power customers.

Finally, Mr. Oliver observed that LP-5 and LP-6 customers are not the only classes which have customers billed on the basis of magnetic tape metering. Thus, the $77.00 figure in PP&L's data must be applicable to customers in other classes as well. Indeed, the record shows that most LP-4 customers and approximately 4% of GS-3 customers also have magnetic tape metering. The expense per customer figures for these LP-4 and GS-3 customers do not reflect magnetic tape metering costs. Thus, the customer accounts expenses allocated to these customer classes are understated.

Mr. Oliver summarized the combined effects of his cost allocation changes in Schedule BRO-4 to OCA Statement No. 2. The results show increases in relative rates of return for the RS, GS-1, and GH customer classes. The relative rates of return for all other classes are diminished.

Mr. Oliver reviewed the company's proposed allocation of the revenue increases among customer classes and agreed in part with the company's proposed increase. He stated that the company's concerns regarding the magnitude of the overall base rate increase were valid. The band of plus or minus two percentage points for increases to customer classes and to most individual customer bills, however, may be too unduly restrictive. The goal of moving customer class rates of return closer to the system average, on the other hand, should only be a driving consideration where particularly large variations in class rates of return exist. Mr. Oliver believed that the evidence here tended to support the concept that large commercial and industrial establishments were more risky to serve than residential and some types of governmental customers.

Mr. Oliver evaluated the effects of the company's proposed revenue distribution on the basis of both the OCA and PP&L cost allocation results. Schedule BRO-5 to OCA Statement No. 2 summarizes the effects of applying the company's proposed revenue increase distribution to the composite of quantified OCA cost allocation revisions. These findings indicate that each of the large power classes, as well as the GH class, would yield rates of return below the system average. The GS-3 class would be approximately even with the system average rate of return and the RS and street and area lighting classes would be slightly above the system average rate of return.

Mr. Oliver proposed a shifting of revenue requirements from the GS-1 class to the LP-4, LP-5 and LP-6 as well as GH customer groups. He would accomplish this revenue shift in two steps. First, the revenue adjustment required to have a deviation of the GS-1 rate of return from system average rate of return is calculated. Second, the calculated revenue adjustment is spread proportionately among the large power classes and the GH class on the basis of their own dollar deviations in system average rate of return.

In the event the Commission grants PP&L less than its full requested increase, Mr. Oliver recommended that residential and street lighting classes receive a dollar reduction in their revenue increases equal to 1.1 times the average percentage reduction for the system. In a similar manner, he would reduce the revenue increase proposed by OCA for the GS-1 class by 1.2 times the system average reduction. The remainder of the reduction of the requested revenue increase would then be spread proportionately among all other classes on a basis of the dollar increases proposed for those classes. He believed that through this method of adjustment gradual changes in the rates of return for all classes would be achieved.

In reviewing the PP&L residential rate design recommendation, Mr. Oliver identified three areas of concern. First, Mr. Oliver found the proposed increase in the residential customer charge to be inappropriate. Mr. Oliver noted the RS class is the only class for which PP&L collects customer-related costs through monthly customer charges. For each of the other customer classes, customer-related costs are collected through energy charges. The GS-1 rate schedule is the only other major rate schedule that includes a flat monthly charge per customer, but his analysis finds that the GS-1 rate schedule essentially collects no customer-related costs through the monthly per customer charge. This occurs because the customer charge in the GS-1 rate schedule is designed to include four kilowatts of demand. Mr. Oliver believed that if it is not important for PP&L to collect its customer costs through customer-related charges for GS and LP rate schedules, it is not necessary to collect it for residential customers through the residential charge in the RS rate schedule. Furthermore, if collection of customer-related costs through energy charges is acceptable under other rate schedules, he found no inherent reason why a similar method of collecting customer-related costs would be inappropriate for residential rate schedules. Mr. Oliver recommended that the residential customer charge be held at approximately its current level and that the energy block rates for the RS rate schedule should be increased slightly to compensate for the loss of customer charge revenues. Mr. Oliver proposed a customer charge of $3.80 per month; a first block energy charge of 8.1¢ per kilowatt hour, and an energy charge for all usage in excess of 200 kilowatt hours per month of 6.1¢ per kilowatt hour (Schedule BRO-9, OCA Statement No. 2). Under the rate he proposed, no residential customer would receive an increase of more than 27.5 percent or roughly 1.1 times the class average increase. However, small users would receive noticeably lower bills under his proposal than they would under PP&L's RS rate proposal.

In reviewing the RTD and RTS rate schedules, Mr. Oliver found that the nearly 50% increase in the demand charge for on-peak kilowatts proposed by PP&L for rate schedule RTS is inappropriately large. This proposed increase in the RTS demand charge is nearly two times the average percentage increase for the residential class. He proposed that the demand charge for rate schedule RTS be held at its current level and that any resulting revenue deficiency for the RTS class be collected through an increase in the energy charge for that rate schedule.

For the RTD rate, he found the proposed $4.25 per kw demand charge to be inappropriate and unnecessary. He recommended that this charge be deleted from the RTD rate schedule.

Under the company's separate water heating service rider to rate schedule RS, a provision would be added that would require the customer to "provide and install any control device specified by the company." The cost of such control devices, Mr. Olvier stated, can vary noticeably and no customer should be required to take on such an open-ended obligation.

E. Position of Large Industrial Intervenors

LVPC and Bethlehem Steel presented testimony of Mr. Maurice Brubaker. Mr. Brubaker testified regarding the selection of the appropriate demand allocation methodology for PP&L, the appropriate allocation of the allowed rate increase among customer classes, and the design of rate LP-6. Mr. Brubaker testified that, based upon a detailed analysis of the company's load pattern and generating unit maintenance practices, it is clear that PP&L exhibits a strong winter-peaking characteristic. Generally, he stated, the winter peak has exceeded the minimum monthly peak by more than 40% and in recent years the winter peak has exceeded the summer peak by 25%. Similarly, the ratio of the winter peak to the average of the 12 monthly peaks indicates that the winter peak is typically 20% greater than the average of the 12 peaks. Mr. Brubaker also stated that, based on his studies, PP&L has a lower reserve margin during the winter months than during the other months. This confirmed, in his view, the appropriateness of focusing upon winter peak loads for the purposes of cost allocation. A review of the company's maintenance practices indicated, according to Mr. Brubaker, that PP&L attempts to schedule the majority of its maintenance during the spring and fall periods (Large Industrial Exhibit MEB-1, Schedule 5).

Mr. Brubaker stated that he disagreed with the company's proposal to use the average of the 12 monthly coincident peak demands for allocating fixed production and transmission related costs. From a review of PP&L's system load data, including consideration of its scheduled maintenance requirements, it is clear, he stated, that the winter peak demands are the predominant driving force behind the need to add production system capacity. Capacity installed to meet the average of the 12 monthly peak loads would be insufficient to meet the winter peak requirement. In the test year, the winter peak is 4,919 megawatts, while the average of the 12 monthly peak loads is 4,063 megawatts. Thus, he stated, the winter peak is approximately 20% greater than the average of the 12 monthly peaks.

On the basis of the test year load characteristics, he believed that the most appropriate methodology for allocating fixed generation costs is one based on the demands at the time of the January and February peaks. The peak load occurs in January, and the February monthly peak is 95% of the annual peak.

Use of the 12 monthly coincident peak dilutes the cost-causative nature of the annual system peak load and permits customers, who are most responsible for the winter-peaking shape of the system, to escape a substantial part of the cost responsibility associated with the high peak load.

Mr. Brubaker stated that a review of the data in this record clearly indicates that the winter-peaking shape of the company's load is primarily driven by the loads of the RS class and the GH class.

Mr. Brubaker prepared cost-of-service studies based on the two coincident peak allocation methodology, the three coincident peak allocation methodology (December, January and February), and the four coincident peak methodology (December, January, February and March). From his analysis of the results of the two coincident peak cost-of-service study, Mr. Brubaker concluded that the residential and heating class customers are producing rates of return well below the average, and will continue to produce rates of return well below the average under PP&L's proposal. Conversely, all other customer classes, including rate LP-6, would be overcharged to a larger degree under proposed rates than is the case under present rates.

Mr. Brubaker developed a recommended allocation of the proposed rate increase. The primary objective in distributing a rate increase, he stated, should be to bring the revenues of each customer class closer to cost of service. He developed an allocation which would reduce the existing inter-class subsidies by approximately 50%.

Mr. Brubaker disagreed with the manner in which PP&L has proposed to increase the various components in rate LP-6. He stated that PP&L has placed far too much emphasis upon the high load factor energy blocks of the rate for the recovery of additional fixed costs. By PP&L's own calculations, the variable cost component of rate LP-6 is only about 1.7¢ per kwh. Thus, the proposed tailblock of PP&L's rate LP-6 (3.4¢ per kwh) is roughly two times the variable cost recovery level. This design of rate LP-6 recovers substantial amounts of fixed costs in the tailblock of the rate and provides a lesser incentive for customers to improve load factor than with a rate design which relies less upon the tailblock of the energy rate for the recovery of fixed costs. Placing a high level of fixed cost recovery in the tail step of the energy charge portion of the rate also subjects the company's recovery of fixed costs to greater uncertainty than would be the case if larger amounts of fixed cost recovery were placed in the demand charge and in the earlier blocks of the rate. He also disagreed with the energy blocking of this rate. The average hour's use for customers on LP-6 is 481 (66% load factor). Under the energy blocking of rate LP-6, the tail step of the energy rate begins when consumption reaches 250 hours' use (34% load factor). In his opinion, this is an insufficient energy blocking for rate LP-6. At a minimum, there should be an energy charge block that begins at an hour's use level higher than the average for the rate. This will more properly recognize the varying load factors of customers taking service under rate LP-6. His recommendation is to combine the first two blocks of the current rate so that the initial block covers consumption up to 250 hours' use, insert a second block for the next 250 hours' use, and insert a tail block for consumption over 500 kwh hours' use.

F. Position of Harrisburg

The City of Harrisburg and the County of Dauphin presented witness Jack D. Ruppe, who testified with respect to the relative rate of return earned by the rate classes at present and proposed rates.

Mr. Ruppe did not agree with the company's position that due to the magnitude of the increase it should be assigned to each class on a fairly uniform basis. According to Mr. Ruppe, the results of the monthly peak responsibility study sponsored by the company show that some rate classes yield returns considerably above system average at both present and proposed rates, while others yield returns below the system average. The proposed class increases recommended by the company would, according to Mr. Ruppe, result only in modest changes in the return earned by the various classes.

While Mr. Ruppe agreed as a general proposition that having each class pay neither more or less than the cost of service is a desirable goal, from a practicable standpoint, he stated, there are several reasons for limiting the movement toward an average return for the various classes. Here, he believed, the primary reason is the disruptive impact a very large increase might have on affected consumers. In addition, because the accuracy of class cost studies is not absolute, exclusive reliance on their results may not be appropriate.

In his view, rate classes GS-1, GS-3, and street lighting all yield returns considerably above system average both at present and proposed levels. The return for rate class GH is considerably below average at present and proposed rates, while the residential class return is indicated to be well below system average, according to Mr. Baldwin's studies. Mr. Ruppe agreed, however, that that return is likely to be understated because of the minimum distribution system allocation methodology utilized by PP&L witness Baldwin.

Mr. Ruppe recommended that increases to rate classes GS-1, GS-3, street lighting, and GH be designed to reduce by one-half the differences between the class rates of return and the system average return. He recommended the balance of the proposed increase be recovered from other classes in the same proportion as recommended by the company.

Mr. Ruppe disagreed with OCA witness Oliver's classification of demand and energy-related costs. Specifically, he disagreed with Mr. Oliver's proposal to classify a portion of bulk power supply facilities costs as energy related in his "average and peak" allocation methodology. He noted that Mr. Oliver is proposing that a portion of bulk power supply facilities be allocated on the basis of average demand (energy) responsibility on the grounds that such base load facilities exist to meet energy requirements. He further noted that Mr. Olvier concluded that the cost of facilities to meet average demand is energy related to the extent that the cost exceeds the cost of capacity. That conclusion, he stated, is based on an observation that if PP&L proceeds with generation needs for additional capacity only during the hour of system peak demand, it could satisfy that need with low-cost peaking capacity or by making capacity deficiency payments to PJM. Mr. Ruppe stated that Mr. Oliver's conclusions are based on his consideration of a peak-hour situation and it is doubtful that this analysis can be expanded for the purpose of determining the capacity requirements to meet average demand. Average demand, Mr. Ruppe stated, is the measure of a continuous requirement to satisfy customer's rate of use of energy (which is demand). That continuous obligation to provide capacity is best met from base load generation capable of sustained reliable operation. Peaking units are neither designed or intended to operate over sustained periods. Therefore, it is wrong to use the cost of such facilities to determine capacity costs of facilities capable of such operation.

G. Position of Medium Industrial Customers

EPEA presented the testimony of witness Charles W. King on rate structure.

Mr. King represented customers taking service under PP&L's GS-3 and LP-4 tariff schedules. He discussed the distribution of the rate increase among customer classes and evaluated the distribution of the rate increases within the GS-3 and LP-4 classes. Mr. King believed that PP&L's rates fail to reflect the cost of serving respective customer classes and that the varying rate of return percentages among the different rate classes demonstrate a pattern of discrimination among various customers. Specifically, he stated, PP&L's rates demonstrate a pattern of discrimination in favor of the residential and space heating classes and against the two general service classes. He criticized PP&L's attempt to apply a uniform across-the-board twenty-five percent increase to all customer classes. Mr. King believed that even if the Commission accepts the proposition that the rate increase should be across-the board, it should act to ameliorate the unreasonable burden of PP&L's proposal on GS-1 and GS-3 customers by reducing their effective rate increase, inclusive of the ECR, to the average for all customer classes. Under PP&L's proposal, that increase would be 19.4%.

Mr. King stated that the PP&L allocation procedure does not conform with Section 115 of PURPA. That section requires utilities to recognize the extent to which total costs respond to additional capacity added to meet peak demand relative to base demand. According to Mr. King, most of PP&L's monthly peaks do not approach PP&L's peak demand during the study year. In fact, the closest monthly peak came to only 84.6% of the annual peak.

Mr. King criticized PP&L's use of the 12 coincident peak method for allocating generation and transmission costs. While PP&L has a requirement to schedule maintenance of its generation plants during months when system demand is below the annual peak, and this under certain circumstances might justify a 12 peak demand allocation, in the case of PP&L this does not hold true.

He also criticized PP&L's witness Baldwin's justification for the 12 coincident peak method as recognizing the PJM installed capacity obligation. Mr. King testified that presumably this consideration flows from the fact that the PJM power pool experiences its peak during the summer months in contrast with PP&L's winter peak. He noted that the basic objective of the PJM power pool is to share power resources so as to minimize both the pool's and the individual company's reserve requirements needed to maintain an adequate level of reliability. Individual members, however, are expected to construct plants sufficient to meet their own demand. Individual members are not expected, however, to construct plants specifically for the purpose of selling into the power pool. The principal determinant of PP&L's capacity obligation to the PJM power pool is its own peak demand which occurred in the winter.

The witness criticized Mr. Baldwin's third justification for using the 12 coincident peak method, i.e., the recognition of seasonal class diversities. While such recognition is relevant to the selection of a demand cost allocator, Mr. King stated, recognition of this factor requires the rejection, not the acceptance of Mr. Baldwin's method. According to Mr. King, that factor totally fails to recognize seasonal load differentials among customer classes. If, for example, a class is heavily off-peak, it receives no credit for its lower impact of system generating requirements. Instead, it is charged equally for its contribution to off-peak as well as on-peak monthly demand. Conversely, a heavily on-peak class escapes responsibility for the burden on system generating capacity by watering down its on-peak usage within an average that includes off-peak months. For example, he stated, the GH class imposes a relatively high demand during January, PP&L's peak month, but that January load has exactly the same weight as the negligible demand of that class during PP&L's off-peak months of May through September.

Mr. King stated, however, that Mr. Baldwin's final justification for his selection of a 12 coincident peak demand allocation procedure, i.e., that of long term stability, is probably the most justifiable. The class make-up of the single hour of system peak load is potentially an instable allocator, particularly when that peak is created by weather characteristics. Mr. King stated, however, the solution is not to adopt Mr. Baldwin's method but to use another measure of annual coincident peak. Probably the best procedure, he stated, would be to use an average of the class make-up of the 10 or 20 peak hours during the year. He stated that to the extent peak demand allocators are used to assign generation and transmission costs, those allocators should reflect PP&L's coincident peak load which occurs in the winter.

Mr. King stated that peak demand should not be the sole allocator of generation costs, particularly when those costs include the Susquehanna Nuclear Plant. While growth in peak demand was responsible for the decision to build the Susquehanna Plant, the decision to make that plant nuclear, rather than fossil-fuel fired, was based on a trade-off between investment and energy costs. For this reason, he believed it appropriate to allocate some generation costs among customer classes on the basis of energy consumption.

Mr. King recommended the "average and excess" procedure using the differential between the respective customer classes' average demand and their demand during the system coincident peak as the allocator of the excess. He explained that the average and excess procedure divides all demand costs into two categories based on the load factor of the system. Demand costs equivalent to the average load, or effectively the system load factor, are allocated according to the average demands of the respective classes. In the case of PP&L, the system load factor is approximately 60%, so that 60% of the generation costs should be assigned on the basis of class average demand, which equates to class energy consumption. The remaining 40% should be allocated among customer classes according to the distribution of the differential between the class average demand and the class consumption during the system coincident peak.

Mr. King stated that his procedure differed from PP&L's "average and excess" demand allocation in that PP&L's employs class non-coincidence peak as the basis for allocating the excess component of demand costs, rather than class consumption at system coincident peak. Since class non-coincidence peaks do not determine or even influence the requirement to construct new capacity, they are irrelevant to the class responsibility for the costs of that capacity, according to Mr. King. He criticized the Consumer Advocate's peak and average method in that it double charges high load factor customers for their consumption at peak: once in the average demand allocation, which for a 100% load factor customer equals peak demand, and again in the peak allocation. His procedure recognizes that the peaking capacity of the system is designed to respond to the differential between the average and the peak, and it only charges this cost to class demands at peak which exceed the average.

The witness did not recommend that the Commission attempt to equalize class rates of return in this proceeding. His first reason for this was the unavailability of a cost of service study which conformed to what he believed to be the best procedure for allocating generation and transmission costs. Secondly and more importantly, he stated that the class returns under the winter coincidence peak allocation procedure are at best so unequal that any effort to equalize them would result in extreme disparities in the rates of increase among customer classes. He recommended that the Commission require PP&L to move class revenues toward equality with class costs by establishing limits on the degree of inequality among class rates of return. There are two standards which he recommended be applied in the present instance. One would attempt to move each class toward equality in cost responsibilites but within the limits that no class should receive more than 150% of the system average increase, and no class should receive less than 50% of the average increase in rates. The other standard would establish a limit of permissible digression from the system average rate of return among respective customer classes. He cited the example of the New York Public Service Commission which employs a 10% band. Any class whose rate of return is between 90% and 110% of the system average is considered revenue-adequate, that is, its rates are not unreasonably out of balance with its cost occurrence. If a class has a rate of return below the tolerance limit, it will receive a supplemental revenue requirement sufficient to bring it up to 90% of the average return. Conversely, any class which generates a rate of return in excess of 110% of the average return receives a credit for revenue sufficient to reduce its return down to that upper limit. After studying the effect of these two methods on PP&L's rates at the present time, Mr. King believed it would be necessary to employ a 20% tolerance band around the system average rate of return.

Mr. King also testified regarding tariff schedules GS-3 and LP-4. He noted that these tariff schedules apply to medium to large commercial establishments and small industrial plants. The minimum size is 25 kw of maximum demand. There is no maximum size, but GS-3 applies only to customers receiving power at secondary voltage and LP-4 applies to customers on primary voltage power supply. The structure of the two schedules is identical. PP&L's proposed increases would increase base energy charges more than base demand charges. Base energy charges would increase on the order of 36% to 42%, while demand charges would increase in the range of 25% to 35%. The combined effect of the greater increases in demand charges and the unequal increases in energy charge blocks would be to grant to high load factor customers lower rate increases than to low-load factor customers. According to Mr. King, PP&L has presented no evidence that its tariff should become more than demand charge intensive. While imbedded demand costs will increase as a result of the Susquehanna unit, and energy costs will decline, Mr. King believed there is good reason for treating a large portion of the Susquehanna Nuclear Plant costs as related to energy. He recommends that PP&L redesign its GS-3 and LP-4 rate schedules so that there is a uniform percentage increase in all elements of the rate, inclusive of the ECR, between 1982 and the effective date of the new charges.

H. Position of the Pennsylvania Industrial Coalition

Pennsylvania Industrial Coalition (PIC) presented the testimony of Edward A. Cecil (PIC Statement No. 1). Mr. Cecil stated that members of PIC receive service from PP&L primarily under rate schedules LP-5 and LP-6. Mr. Cecil presented testimony on cost allocation and rate design. He recommended adjustments to the PP&L demand cost allocation study which were based on the average and excess method. These adjustments, he stated, were needed to make the study conform to the standard approach to applying the average and excess method. Furthermore, he proposed that the Commission consider using "a properly applied" average and excess method of allocating demand costs in this proceeding. Mr. Cecil testified that although PP&L advocated use of a 12-monthly peak method, it departed somewhat from the method in applying a uniform 25% increase to the revenues produced by the present rates. PP&L, he stated, justified this departure on the basis that its results approximated the results of using a 12-monthly peak method, treated all classes evenhandedly, and moved most classes closer to the average system rate of return. While holding that there is no single correct cost allocation methodology, Mr. Cecil stated that one should strive to allocate costs on the basis of maintaining as close a relationship as possible between the costs assigned to a particular customer class, and the system's actual cost of rendering service to that class. Mr. Cecil stated that a customer causes a utility to incur costs both through its capacity utilization, represented by its peak demand, and through its total energy consumption. A method which recognizes and gives weight to both factors would fairly recognize each class's cost responsibility on a system. The average and excess method achieves this result; therefore, he suggests this method be given strong consideration in this case as a method of fairly allocating PP&L's costs between customer classes.

In the average and excess method, demand costs are allocated by giving some weight to characteristics of use: the non-coincidental peak demand of each class, and the average energy use of each class. The average and excess method, he stated, avoids the drawback of the various peak responsibility methods which, because they consider only demand at the time of system peak, make it possible for some classes to enjoy a "free ride" on the system with respect to generation and transmission demand costs. He did not recommend, however, adopting the average and excess demand method shown in PP&L's cost allocation study (PP&L Exhibit AJB-3, Section VI, page 4). He reached this conclusion because, in his opinion, PP&L has not used standard application of the average and excess method in its study. An adjustment would have to be made in order for it to conform to the standard practice. According to the witness, the standard practice to adjust the class excess demand so that the total demand used for allocation is the annual peak demand for the jurisdiction. In this case, he stated, the amount would be the winter peak demand of 4,688 megawatts shown in PP&L Exhibit AJB-3. PP&L, however, adjusted the class excess demands so that the total demand used for the allocation of generation and transmission demand costs equaled the Pennsylvania jurisdictional average monthly responsibility amount of 3,893 megawatts. Under Mr. Cecil's method, the allocated cost of service would be reduced for GS-3, LP-4, LP-5 and LP-6 classes. It would be increased for the RS, GS-1 and GH classes (PIC Statement No. 2, page 17).

I. Position of St. Regis Paper Company

St. Regis Paper Company presented the testimony of Mr. Harold Cook (St. Regis Paper Company Statement No. 1). Mr. Cook analyzed the costs and load characteristics of the PP&L system and reviewed the company's class cost of service procedures. He found that the allocation procedure used with respect to demand-related costs was inappropriate given PP&L's load characteristics. It was his position that use of the monthly peak allocation procedure is improper because it permits those customers who are most responsible for the system load shape to be subsidized by other customers on the system.

Mr. Cook testified that the addition of Susquehanna Unit No. 1 to plant in service has increased PP&L's rate base approximately 67%. This has changed the basic cost structure from previous periods. If an attempt is made, he stated, to recover the increased fix costs through the energy component of rates, revenue instability could result. He also stated that the initial planning of Susquehanna was prompted by the need to meet projected increases in peak loads on the PP&L system.

He testified that the object of a cost of service study is to study the utility's system and to allocate costs according to their cause. With respect to power production costs, what is being allocated are power supply demand-related costs, predominantly production and transmission plant. The amount of capacity for production and transmission that has been installed over time in a utility's sytem is designed to meet the annual system peak load plus a reasonable reserve. The responsibility for those costs should be apportioned among the customer classes based on the relative responsibility of creating the peak. According to his studies, the company's winter peaking load shape is being driven by the electric home heating customer, and that the swings on PP&L's daily system demands are the results of the variation power requirements of customers other than the large power customer. In summary, his analysis purportedly demonstrates that the PP&L load pattern, both seasonal and daily, is influenced primarily by the load characteristics of the residential class and particularly the loads of residential customers with electric home heating. The residential class exhibits the greatest month-to-month variation in demand and the greatest variation in demands over a 24 hour daily period. His analysis of the system load pattern indicates that the demands imposed on the system during the winter peak period are the most critical demands. Accordingly, he stated, these demands are the ones that should be given greatest weight for the purpose of assigning power production cost responsibility to the various customer classes. Use of any allocation method which weights or averages demands, other than winter peak demands, allows those customers who are most responsible for the system load shape to be subsidized by other customers on the system.

Based on this analysis of system load characteristics, he recommended that those costs be allocated to customer classes in proportion to the class coincidence demands occurring at the time of the monthly peaks during the months of January and February. He criticized PP&L's use of the monthly peak responsibility method to allocate fixed production costs. This method, he stated, is a modified peak allocation method in which peak demand and each class' contribution to the monthly peak for all 12 months of the year are averaged. It is his opinion that use of this method is inappropriate because it introduces a degree of irrationality into the costing process. The system, he stated, is built to meet the peak. Production plant, as well as the transmission power supply facilities, are keyed to this peak. The introduction of broad averages for the costing of power supply facilities tends to separate those who cause the costs from those who bear the cost. The use of monthly peak method dilutes the demand responsibilities of the residential class. He further stated that use of the average of 12 monthly demands has a tendency to assess more cost responsibility to those customer classes whose consumption is steady throughout the year, i.e., the industrial classes. Mr. Cook presented his own study (Exhibit HC-1, Schs. 13 & 14). His study incorporates cost allocation procedures which he believes properly reflect cost incurrence on the PP&L system. Power supply investment and expenses including the production and transmission function have been allocated to the customer classes on the basis of the class' contribution to the monthly coincident demands projected to occur in the months of January and February of the future test year. The cost-based procedure used in his study assigns more costs to the residential class and less cost to the commercial and industrial classes.

St. Regis Paper also presented as a witness in this proceeding Mr. Kenneth Eisdorfer (St. Regis Statement No. 2).

Mr. Eisdorfer proposed that PP&L's proposed revenue distribution be rejected. Instead, he structured a revenue distribution to reduce existing class subsidies by 50%. This result, he says, recognizes concept of moderation in customer impact and is more reflective of class cost incurrence.

Mr. Eisdorfer also testified as to the design of rate LP-4, the rate under which St. Regis is served. In general terms, he stated, the goals of the rate design process should be the eventual elimination of intra-class subsidization and the minimumization of the potential for overall earnings instability. These goals are best achieved when a tariff's energy charge is limited to the recovery of variable costs. Fixed costs should be recovered in other portions of the tariff. Under the company's proposal for rate LP-4, the proposed tail block energy charge is 38 mills per kwh. Mr. Eisdorfer analyzed the variable costs incurred by PP&L serving rate LP-4. He concluded that it is not more than 18.5 mills per kwh. Consequently, over half of the proposed tail block energy charge would be devoted to fixed costs recovery. By attempting to use the majority of the proposed tail block energy charge to recover fixed costs, he stated, the company is aggravating the potential for revenue instability. Mr. Eisdorfer proposed a recommended design for rate LP-4 (Exhibit KE-1, Schedule 17). This proposal is predicated on setting the tail block energy charge at 28.5 mills per kwh. His recommended rate, he stated, would result in less intra-class subsidization and lower earnings instability potential.

St. Regis Paper also presented testimony of Mr. Brian Kalcic. The witness stated that the more fixed costs that are attempted to be recovered in the tail block energy charges of rate LP-4, the greater the potential for earnings instability. His analysis showed that rate LP-4 energy usage exhibits greater variance over time than billing demands. Thus, fixed cost recovery will be more volatile if recovered in an energy rather than demand charge.

J. Position of CEPA

CEPA and the Susquehanna Alliance argue in their brief that rates should not be increased to persons at or below 150% of the OMB poverty level. In addition, they request the Commission to direct PP&L to list separately on the bill all fixed charges that do not vary with consumption.

As stated earlier in this decision, since these matters were never specifically raised during the hearing, consideration of them at this late date would not be proper.

K. Discussion

There are three basic areas for Commission resolution: (1) the appropriate cost of service study to be used; (2) the appropriate revenue allocation to be used; and (3) the appropriate rate design to be used to collect those revenues.

(1) Cost of Service

If there is one universal truth to be found in this proceeding, it is that any recommendation made by the Administrative Law Judge and any determination made by the Commission can find some evidentiary support in this record and probably withstand any attack on appeal. See Park Towne v. Pa. P.U.C., 433 A.2d 610 (1981). In the ALJ's opinion, PP&L's study suffers from some serious infirmities with respect to its allocation of bulk power costs and its allocation of the cost of its distribution system.

As noted earlier, PP&L allocated its bulk power costs on the basis of 12 monthly coincident peaks. This has been criticized severely by most industrial customers and the Trial Staff and criticized to a limited extent by the OCA.[14/]

I find the criticizm by the Trial Staff and the industrials to have considerable merit - clearly the 12 CP method does not reflect the use characteristics of PP&L's native load customers. The four reasons given by PP&L

14/ The OCA's proffered allocation of these costs would have only a minor effect on the rates of return established by PP&L's study.

for its choice of this methodology (i.e., maintenance scheduling of generation equipment throughout the year; PJM interconnection installed capacity obligation; recognition of seasonal class diversities; and long-term stability [Tr. 609]) have been effectively rebutted on this record. With respect to the first reason, St. Regis witness Cook stated (St. Regis St. No. 1, p. 18):

> There existed a significant capacity margin during the non-winter period. This indicates that the Company has the ability to serve additional demands during the non-winter months. When we realize that Susquehanna Unit 1 will add an additional 945 mw to the Company's capability, this ability is increased significantly. Capacity has been installed to meet PP&L's winter system peak demands and since this capacity is in place for this purpose it is also available during the other months of the year to handle scheduled maintenance requirements and in fact this capacity could be utilized to a much greater extent than is presently the case.

With respect to the PJM interconnection installed capacity obligation, EPEA witness King stated (Medium Industrial St. No. 1, p. 10):

> It is simply not true that PP&L's PJM capacity obligation is based on the pool's summer peak. Document 200.482012 reveals quite clearly that PP&L's capacity obligation is developed from its winter peak load. True, it is later adjusted for a variety of factors, including its summer load, its summer and winter diversity, its forced outage rate and a "load drop adjustment" reflective of weekly peak demands. Nevertheless, the principal determinant of PP&L's capacity obligation to the PJM Power Pool is its own peak demand, which occurs in the winter.

The argument that this methodology recognizes seasonal class diversities fails to give weight to the fact that the size of PP&L's winter peak demands are responsible for the magnitude of its installed generating capacity.[15/] To suggest that those customers who have high loads during off-peak periods are somehow responsible for PP&L's cost incurrence is simply ridiculous. In point

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15/ The claim that PP&L installed additional capacity to meet the requirements of other companies on the PJM system must be rejected.

of fact, to the extent that a given customer can shift his load away from the annual system peak, that customer is helping tq avoid, not incur, costs.

Finally, the assertion that its methodology promotes long term stability must be rejected. As admitted by the company, and as discussed below, its cost of service study played only a minor role in its decision as to how to allocate this increase (Tr. 588, 605). Therefore, this allocation methodology hardly promotes anything.

The Peak and Average Application promoted by the OCA must also be rejected. Without indulging in any theoretic discussion on the merits of OCA witness Oliver's proposal, 16/ this methodology would reward a class that significantly increased its on-peak winter demand by lowering that class' allocable revenue responsibility (Tr. 1858-62). This is a result which hardly deserves to be promoted.

I agree with Trial Staff witness Rosenthal that the customers' use of the system should be the principal guideline for selecting the appropriate allocation methodology for production and transmission plant and expenses. As he noted, customer class use of the electric system is bounded by two parameters: the maximum demand of the class and the kilowatt hour consumption of the class. As he stated, reflection of class use of the system is best accomplished by employing the average and excess method which is based upon the integration of the kilowatt hour consumption with the maximum demand of the class -- the average and excess method essentially uses the class load factor for allocation purposes and reflects the extent to which a class uses the system and the benefit each class receives from having the system in place.

16/ For those interested in such a discussion, the Administrative Law Judge recommends reading Tr. 1808-1865.

It should be noted that any utility must have adequate capacity in place to serve the maximum needs of a class -- the benefit the utility receives from the diversity of its customers is the diminished need to install capacity in relation to the coincident peak of the customers as a whole since the various customer classes are able to share capacity needed for the system peak at all other times of operation. It is this sharing of capacity at times other than system peak, i.e., during the 8,759 off-peak hours per year, that best dictates the allocation of production and transmission plant costs among the various customers classes; the use characteristic of the class is therefore the best measure for allocating plant.

Staff's recommendation, which should be adopted, is to correct respondent's calculation of the average and excess allocator to the so-called "classical" method and to employ such allocator in the cost of service analysis (Tr. 1703). Trial Staff's recommendation that the derived average and excess allocator set forth in T.S. Exhibit 5-A, Schedule 11, be used for the allocation of production and transmission plant and demand relate expenses should be adopted.

The company's functionalization of distribution plant between primary and secondary functions is based upon a study conducted in 1973 (Tr. 622). This functionalization was based solely upon engineering judgment and not upon field examination of the PP&L system (Tr. 627). Since 1973, 13% of the present distribution conductors and 10% of the present distribution poles were added to the system (Tr. 623); accordingly, both Trial Staff and the OCA recommended that PP&L provide in conjunction with its next filing a new study for the functionalization of the distribution accounts between primary and secondary components and a study for the classification of distribution plant between customer and demand components. This should be adopted. The company should also endeavor to correct admitted errors to its current allocation of meter costs (Tr. 639).

OCA witness Oliver also proposed a change in the allocation of the secondary distribution system costs. This would increase the return earned by residential customers by 7% and decrease the return for general service customers. Since large industrial customers are primary distribution customers, this modification would not affect their returns.

This modification would divide the costs of the distribution plant based on demand and energy components instead of customer and demand components.

I agree with Trial Staff that such a change is not supported here. The total elimination of the customer component in distribution lines, poles and transformers, as proposed, disregards the physical construction of the system in its proposed apportionment of distribution costs. Items such as the amount and length of conductors, the number of poles and transformers, etc., are all dependent upon the number of individual service locations and thereby impact on the cost of the distribution system.

Trial Staff argues that integrating energy parameters into the allocation of noncustomer related distribution plant has little impact compared to the use of non-coincident demands; for example, it states, if one compares the percentages associated with the D-20 allocators (PP&L Exhibit AJB-3, Section B, p. 20) for the noncoincident peak method with the average and excess demand method, there exists only minor differences in the allocation.

This proposal should not be adopted.

In summary, it would appear that Mr. Rosenthal's proposal, as detailed in St. Regis Exhibit KE-2, Schedule 2 (appended to this decision as Appendix C) should be used to evaluate the revenue allocation proposals of the various classes.

(2) Revenue Allocation

Cost of service studies, despite the controversies that always surround them, are not ends in themselves, but are strictly guides to assist in the allocation of a revenue increase among the various classes of customers. Of course, since rates must have their basis in the cost of serving each customer class, these studies should play a major part in any Commission determination.

The company here is proposing an across-the-board allocation due to the magnitude of the revenue increase sought (PP&L St. 5, p. 10). This type of allocation would, it believed, mitigate the public outcry which it anticipates will be the result of this proceeding.

Cost of service data apparently played little part in management's decision to seek the allocation as evidenced by the following exchange between PP&L witness Baldwin and counsel for Bethlehem Steel (Tr. 593):

> Q. Were the studies that were given to senior management based exclusively on the 12 coincident peak method of allocation that the company prefers and that the company has used in its two studies introduced into evidence in this case?
>
> A. It's my recollection that our general discussion with senior management dealt only with the cost allocation recommended by the company in this case.
>
> Q. Therefore, the indicated rates of return would be the same as the ones that you have put into evidence or very close to it?
>
> A. It would be very close or exactly the same as the results of the average of 12 contribution to monthly peak.
>
> Q. The use of the 12 coincident peak method that you have used here, and that I believe was used in prior cases is a selection of methodology by senior management or by members of the Rate Department?

A. I would characterize that as a Rate Department recommendation accepted by management.

Q. But they didn't really know the alternatives in this case because they were only given the 12 CP study, right? As far as indicated, rates of return or other Methodologies?

A. We spent little or no time on other methods.

Q. You did have to do other methods, right, in order to meet the filing requirements? Didn't you have to provide that in this case?

A. We did, indeed (Tr. 593).

On the other hand, certain experts would place considerable more emphasis on cost of service principles, the result of which would be increases of over 36% to residential customers and 40% to space heating customers - even after application of the principle of gradualism (Large Industrial Exhibit EB-5, Sch. 3). Still, other witnesses, attempting to move all classes closer to the system average rate of return, recommend that this Commission move class revenues toward equality with class cost by establishing limits on the degree of inequality among the class rates of return. EPEA witness King (MI St. 1, pp. 18-21) proposed two standards to be applied in the present case. The first is the standard adopted by the Florida Public Service Commission and accepted recently by the New Hampshire Public Service Commission. This standard attempts to move each class toward equality in cost responsibility but within the limits that no class, no matter how undercharged, should receive more than 150 percent of the system average rate increase, and no class, no matter how overcharged, should receive less than 50 percent of the average increase in rates.

The other standard is the New York "tolerance band" procedure. Under this procedure, the Commission would establish a limit of permissible digression from the system average rate of return among the respective customer classes. For larger utilities with more refined costing procedures, the New York Commission has employed a 10 percent band. Any class whose rate of return is between 90 and 110 percent of the system average return is considered revenue-adequate, that is, its rates are not unreasonably out of balance with its cost incurrence. If a class has a rate of return below the tolerance limit, such as 85 percent of the system average, it receives a supplemental revenue requirement sufficient to bring it up to 90 percent of the average return. Conversely, any class which generates a rate of return in excess of 110 percent of the average return receives a credit for revenue sufficient to reduce its return down to that upper limit. 17/

Mr. King recommended a combination of both the Florida and the New York standards. As he explained, the purpose of the two concepts is somewhat different. The objective of the Florida 150%/50% limitation is to ameliorate the differentials in the rate increase among the customer classes. The objective of the New York procedure is to recognize some tolerance of disparities among customer class returns. By applying the Florida 150%/50% limits, he determined the appropriate tolerance band to be applied to PP&L under the New York procedure.

Specifically, he applied the conventional 10 percent New York tolerance band, allowing variances from PP&L's jurisdictional average rate of return within the limits of 90 to 110 percent. He discovered, however, that this tolerance band, applied to PP&L's cost of service study filed in this proceeding, would result in some classes receiving increases twice those of

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17/ Mr. King also recommended that each class be given a uniform increase to meet its adjusted revenue requirements.

the system average overall and other classes receiving virtually no increase whatever. He therefore determined that in order not to violate the 150%/50% constraint, it would be necessary to employ a 20 percent tolerance band around the system average rate of return.

Mr. King's recommendations appear to be a reasonable approach to the question of allocating the revenue increase here. The company's approach, supported by the OCA, would only increase in magnitude the interclass subsidization which is now occurring. Although the company and the OCA point out that the indexes of return are actually narrowing, the dollar differences would increase considerably and, in the real world, it is dollars not percentages which are important. Trial Staff's approach (T.S. Exhibit 5-A, Sch. 14) moves in the right direction, making limited adjustments to the increases assigned to five rate classes, but at an unacceptably slow pace.

Mr. Eisdorfer's and Mr. Brubaker's allocations, however, would move too swiftly. Mr. King's recommendation appears, therefore, to be the most reasonable.

(3) Rate Design

The various contested aspects of PP&L's rate design proposal will be discussed below. Those individual items not discussed below have been reviewed and are recommended to the Commission for implementation.

(a) Residential Rates

The company has recommended that its residential customer charge be raised from $3.77 to $4.75. The Consumer Advocate has opposed this particular proposal. This increase is necessary for PP&L to begin to recover the costs which it incurs whether or not a customer consumes electricity. These costs, which include meter-reading, bill preparation and other fixed charges, exceed the \$4.75 level proposed by PP&L regardless of whether the company's estimate of \$12.20 (Tr. 1903) or the OCA's cost estimate (\$7) are employed. The company's position should be adopted.

The company has proposed several revisions to its existing time-of-day rates in an effort to make this type of service more attractive to its customers (PP&L Exhibit AFB 4, pp. 13-14). First, Rate RX, now applicable only on an experimental basis, would be replaced by Rate RTD which would be available to all residential customers. In addition, proposed Rates RTD and RTS would permit a customer to select any consecutive 12 hours (starting and ending on the hour) within the 7AM - 9PM weekday period as the on-peak period for billing purposes. Finally, in order to limit any adverse impact of demand charges on the residential time-of-day customer, six major holidays would be excluded from the on-peak period under Rates RTD and RTS (PP&L Exhibit AJB 4, pp. 13-14).

The only controversy centers on the OCA's opposition to PP&L's proposed \$4.25 per kw demand charge on the RTD and RTS rate schedules. This opposition is based in large measure on the OCA's allocation of part of the bulk power supply costs to energy instead of demand as proposed by the company. I recommended earlier against adoption of the OCA's allocation methods for these costs. Consistent with that recommendation, I would reject the OCA's proposal here also.

(b) <u>Rates GS-3, LP-4, LP-5 and LP-6</u>

Few parties, if any, are happy with the company's proposed GS and LP rate schedules. The OCA believes that PP&L's assignment of charges between the demand and energy components of the LP and GS rates places too much emphasis on demand, while it underprices the energy component of these tariffs. This rate design conflicts with the OCA's allocation of costs for bulk power facilities. Since the OCA's allocation methodology has been rejected, its criticism here should carry no weight.

Trial Staff proposed rates for GS-3, LP-4, LP-5 and LP-6 customers as alternatives to those proposed by the company. As noted above, using PP&L's load and cost data, Trial Staff employed a procedure which, it claims, reflected both the pattern and level of customer cost occurrence. Using the customers' coincidence factor versus load factor relationships, Trial Staff integrated the total cost of service with the energy blocking of the various rates. It submits that PP&L's proposal for straight percentage increases to the various rate blocks disregards totally the pattern of cost occurrence and the load characteristics of its customers.

Trial Staff notes that PP&L witness Baldwin agreed that a large portion of the present rate increase request reflects the recognition of SSES Unit 1 in base rates (Tr. 582). This implies that cost-based rates need to reflect a larger portion of the increase in the demand charge; instead, it argues, the company proposed more of the increase on a percentage basis in energy block rates as might indicate that it was PP&L's fuel cost which had increased rather than its fixed capital cost. The effect of such a price signal could well be an unwarranted reduction in energy use and, therefore, an underutilization of a very expensive capital investment.

Trial Staff argues that its commercial and industrial rates comport more favorably than do PP&L's to the "inverse elasticity" principle of utility pricing (Tr. 1781, 1782), which asserts that any rate increase should be allocated in such a way as to minimize the change in each customer's demand as a result of the increase; Trial Staff maintains that incrementally allocating increases where demand is most price inelastic would accomplish this goal.

Here, the inverse elasticity theory translates into relatively larger increases in the demand charge and initial energy block (where usage is more price inelastic) and smaller increases in the subsequent energy blocks (where usage is more price elastic). Instead, PP&L has proposed what might be characterized as "excess burden" on customers -- in addition to the financial burden of the rate increase, customers are also forced to bear an externally imposed distortion of their private consumption choices.

EPEA opposed Trial Staff's "marginalist" approach, which it claims was inappropriate for a company with excess capacity.

EPEA also opposed PP&L's design of the GS-3 and LP-4 tariff schedules. It argues that PP&L's proposed increases for the GS-3 and LP-4 tariff schedules lack symmetry between the base rate increases and the reduction of the fuel rate which would presumably be caused by the substitution of nuclear for fossil fuel and the recent decline of fossil fuel costs. It maintains that the company's proposed rates will distort the pattern of rate change, with demand costs going up and energy costs going down, assuming a continued decline of fuel costs. While PP&L attempted to adust for this effect by increasing the base energy charges more than the base demand charges, it has not fully offset this by its adjustment of the distorting effect of the asymmetrical cost changes.

When the effect of the energy cost rate (ECR) is included in the calculation, the demand charges still increase substantially more than energy charges. Because the proposed base rate increases are on a percentage basis, while the fuel rate reductions are on a flat kilowatt-hour basis, the tail block energy increase is much less than the initial blocks.

Dr. Giordano's recommendations with respect to Rate GS-3 should be adopted. While the case for the "marginalist" approach may not be as compelling here as in the situation of a utility with little excess capacity, this approach still makes better economic sense than that put forth by the company or EPEA.

St. Regis opposed the company's proposed LP-4 rate and agreed with Trial Staff witness Rosenthal that the company's rate design does not reflect the increase in demand-related production facilities and decrease in base energy costs which have marked this proceeding.

St. Regis witness Eisdorfer determined that PP&L's variable energy-related cost of providing service to Rate LP-4 customers is no more than 18.5 mills per kilowatt hour, while PP&L witness Baldwin stated on cross-examination that it was 17.78 mills per kilowatt hour (Tr. 651). Yet, as St. Regis argues, the company is proposing to increase the Rate LP-4 tailblock energy charge from 27.028 mills per kilowatt hour to 38.0 mills per kilowatt hour. In other words, under PP&L's proposal, the Rate LP-4 tailblock energy charge would be more than twice the variable cost incurred by PP&L in serving these customers. When energy charges exceed variable costs, it seems clear that customers with relatively high load factors will subsidize those with lower load factors. Additionally, only when unit energy charges equal unit energy costs can customer revenues equal customer cost imposition over all ranges of consumption -- thereby eliminating intraclass subsidization (St. Regis St. No. 2, pp. 22-25). Furthermore, it is evident that energy charges which greatly exceed energy costs are an invitation to earnings instability.

St. Regis' proposed LP-4 rate is shown below:

Demand Charges per KW

First 200 KW	$8.51
Additional KW	$6.11

Energy Charges per KWH

First 150 hours	4.15¢
Next 100 hours	3.35¢
Additional KWH	2.85¢

Trial Staff witness Rosenthal's methodology produced a proposed Rate LP-4 as follows:

Rate Block	Price $
First 200 KW	7.00
Excess KW	4.75
First 150 KWH/KW	.053
Next 100 KWH/KW	.044
Excess KWH	.032

St. Regis opposes Mr. Rosenthal's proposal, arguing that a 32 mill per kilowatt hour tailblock energy charge would result in 44% of the tailblock energy charge being utilized for the attempted recovery of fixed costs (Tr. 1730).

I believe Mr. Rosenthal's approach best reflects the principles of cost-based rates and gradualism and should be adopted.

Similarly, his recommendations with respect to LP-5, as shown below, should also be adopted (modified, of course, to reflect the reduced revenue requirement):

Trial Staff Proposed Rate LP-5

Rate Block	Price $
First 300 KW	4.65
Excess KW	4.44
First 150 KWH/KW	.047
Next 100 KWH/KW	.041
Excess KWH	.029

With respect to LP-6, Large Industrial witness Brubaker believed that PP&L has placed too much emphasis upon the high load factor energy blocks of the rate for the recovery of additional fixed costs. According to PP&L's own calculations, the variable cost component of Rate LP-6 (at the proposed rate level) is about 1.7¢ per kilowatt hour. The proposed tail step of PP&L's

Rate LP-6 (3.4¢ per kilowatt hour) is roughly two times the variable cost recovery level. According to the witness, this design of Rate LP-6 recovers substantial amounts of fixed costs in the tail step of the rate, and provides a lesser incentive for customers to improve load factor than would a rate design which relied less upon the tail step of the energy rate for the recovery of fixed costs.

Placing a high level of fixed cost recovery in the tail step of the energy charge portion of the rate, he continued, also subjects the company's recovery of fixed costs to greater uncertainty than would be the case if larger amounts of fixed cost recovery were placed in the demand charge and in the earlier blocks of the rate. Mr. Brubaker also criticized the energy blocking of Rate LP-6. The average hour's use for customers on Rate LP-6 is 481 (66% load factor). Under the energy blocking of Rate LP-6 (both present and proposed), the tail step of the energy rate begins when consumption reaches 250 hours' use (34% load factor). In his opinion, this is an insufficient energy blocking for Rate LP-6. At a minimum, there should be an energy charge block that begins at an hour's use level higher than the average for the rate. This will more properly recognize the varying load factors of customers taking service under Rate LP-6.

He recommended combining the first two blocks in the current rate, so that the initial block covers consumption up to 250 hours' use, inserting a second block for the next 250 hours' use and instituting a tail block for consumption over 500 kilowatt hours' use.

He designed a Rate LP-6 by starting with the existing Rate LP-6 and reducing the existing energy blocks to remove the base rate fuel cost. He then applied the proposed base rate increase of about 96% to these rates and added the proposed rate fuel cost recovery to obtain an initial Rate LP-6. He then combined the charges for the first two blocks of the rate, and designed a tail block for consumption in excess of 500 hours' use at a level which would remove approximately one-half of the fixed cost recovery contained in the company's proposed rates. He then adjusted this rate to the appropriate rate level by "scaling down" the derived rate values. This rate design is shown below:

LI Proposed Rate LP-6

Rate Block	Price
Demand	\$4.04/KW
Energy	
0-250 Hours' Use	3.70¢/KWH
Next 250 Hours' Use	2.90¢/KWH
Additional	2.20¢/KWH

Once again, however, it would appear that Trial Staff's proposal, which also has three energy blocks to recognize the varying load factors of customers, should be adopted. Trial Staff's approach takes a more gradual approach while reflecting the cost factors which have caused this proposed increase. This approach, which should be modified to reflect the reduced revenue requirement of this class, is shown below:

Trial Staff Proposed Rate LP-6

Rate Block	Price \$
All KW	4.50
First 150 KWH/KW	.045
Next 100 KWH/KW	.039
Excess KWH	.028

XII. CONCLUSION

Upon review of the record here, I conclude that Pennsylvania Power & Light Company has shown the need for additional revenue relief of \$201,652,000. The amount of rate relief recommended is high, especially in these hard economic times for Pennsylvania, but it represents the lowest reasonable amount that can be supported on this record. It is based on the lowest reasonable valuation of PP&L's investment, reflecting the commercial operation of Susquehanna Unit 1 and consistent with actual operating conditions on the PP&L system. It is based on actual costs which the company is now or will experience during the time the rates set here are in effect. Finally, the return recommended reflects the bare minimum necessary so as not to impair the utility's financial integrity.

THEREFORE, IT IS RECOMMENDED:

1. That the several complaints consolidated with R-822169 be granted or denied to the extent consistent with the Recommended Decision.

2. That Pennsylvania Power & Light Company shall file effective for service rendered on or after the date of enetry of the Commission's Order, or within thirty (30) days thereafter, as it may elect, tariff or tariff supplements prepared in accordance with the Recommended Decision, containing rates designed in accordance with the recommendations herein regarding rate structure to provide annual electric operating revenues of $1,387,931,000 exclusive of state tax adjustment surcharge revenues and net energy clause revenues.

3. That the tax surcharge shall be computed in accordance with the State Tax Adjustment Surcharge Order of March 10, 1970, as revised.

4. That Pennsylvania Power & Light Company shall file detailed calculations with the tariff filing which shall demonstrate to the Commission's satisfaction that the filed rates comply with this Order.

5. That upon the filing of tariff revisions acceptable to the Commission as being in compliance with the Commission's Order and upon Commission approval of the tariff revisions, the inquiry and investigation at R-822169, et al., shall be terminated and the record marked closed.

Recommended to the Pennsylvania
Public Utility Commission

Joseph J. Klovekorn

Joseph J. Klovekorn
Administrative Law Judge

June 24, 1983
Date

TABLE I

PENNSYLVANIA POWER & LIGHT COMPANY
ADJUSTMENT FOR EXCESS CAPACITY
FUTURE TEST YEAR ENDING JULY 31, 1983
($000)

		Total Production Plant - Co.	Adjustment for Overcapacity
1.	Production Plant - PA:		
2.	Plant in Service	$2,699,803	$ (340,584)
3.	Depreciation Reserve	(423,261)	53,395
4.	Net Production Plant	$2,276,542	$ (287,189)

5. $\frac{945 \text{ MWS}}{7,491 \text{ MWS}} \times \$2,699,803 = \$340,584$

$\frac{945 \text{ MWS}}{7,491 \text{ MWS}} \times \$ (423,261) = \$(53,395)$

$\frac{945 \text{ MWS}}{7,491 \text{ MWS}} \times \$2,276,542 = \$287,189$

TABLE II

CASH WORKING CAPITAL

ALJ Adjustments:

Operation and Maintenance Expense	$ (163)
Interest Payments	(5,653)
Preferred Stock Dividend Payments	(65)
Total Adjustments	$ (5,881)

TABLE III

CASH WORKING CAPITAL
OPERATION AND MAINTENANCE EXPENSE REQUIREMENT
($000)

ALJ Adjustment to Expenses	$	(4,247)
Expense Adjustment Per Day	$	(12)
Average Lag Days		13.6
Adjustment to Expense Requirement	$	(163)

TABLE IV

Adjustment to Cash Working Capital for
Semi-Annual and Quarterly Interest Payments

Adjusted Measures of Value (Before Adjustment for Debt Interest and Preferred Stock Dividends)	$ 3,278,743
Capitalization Ratio Long-Term Debt	47.1%
Amount of Net Electric Plant Allocated to Long-Term Debt ($3,278,743 x 47.1%)	$ 1,544,288
Pro Forms Long-Term Interest Charges Allocable to Electric Plant (Embedded Debt Cost of 10.92% x $1,544,288).	$ 168,636
Daily Interest Expense ($168,636 ÷ 365 days Pro Forms Long-Term Interest Charges).	$ 462
Daily Interest Expense--Semi-Annual Interest 89% x $462	$ 411
Daily Interest Expense--Quarterly Interest 11% x $462	$ 51

Days to Mid-Point of Semi-Annual Interest

	90.00 days
Less: Revenue Lag Days	34.20 days
	55.80 days

Days to Mid-Point of Quarterly Interest

	45.00 days
Less: Revenue Lag Days	34.20 days
	10.80 days

Adjustment for Semi-Annual Interest Daily Interest of $411 x 55.8 days	$ 22,934
Adjustment for Quarterly Interest Daily Interest of $51 x 10.8 days	551
Total Interest Adjustment	$ 23,485
Company Claim	29,138
Adjustment	$ (5,653)

TABLE V

Adjustment to Cash Working Capital
Requirement for Preferred Dividend Payments

Measures of Value (Before Adjustment for Debt Interest Preferred Stock Dividends).	$ 3,278,743
Capitalization Ratio Preferred Stock	18.1%
Amount of Measures of Value Financed by Preferred Stock ($3,278,743 x 18.1%).	$ 593,452
Embedded Cost of Preferred Stock Dividends Allocated to Electric Plant ($593,452 x 9.57%).	$ 56,793
Daily Preferred Charges ($56,793 ÷ 365 days) Pro-Forma Preferred Dividends)	$ 156
Days to Mid-Point of Quarterly Preferred Dividends 45.00 days	
Less: Revenue Lag Days 34.20 days	
10.80 days	
Adjustment for Quarterly Preferred Dividends Daily Preferred Dividends $156 x 10.8 days.	$ 1,685
Company Claim	1,750
Adjustment	$ (65)

TABLE VI
SUMMARY OF ADJUSTMENTS
($000)

	Rate Base	Revenues	Expenses	Depreciation	Taxes Other	Income Taxes	Return
Plant Held For Future Use	(751)						
Fuel Oil Inventory:							
Martins Creek	(14,703)						
Repricing of Light Oil and Diesel Fuel	(1,171)						
Coal Inventory	(3,338)						
Excess Capacity	(287,189)						
Hydrodynamic Load Studies	(2,800)						
Cash Working Capital	(5,881)						
Pension Costs			(624)			311	313
EEI Dues			(167)			83	84
Recreational Facilities			(259)			129	130
Management Audit			(266)			132	134
SSES:							
Spent Fuel Expense			(2,478)			1,233	1,245
Decommissioning			(453)			225	228
Taxes:							
Amortization of 2% Overcollection						(204)	204
Amortization of ITC						(1,730)	1,730
Consolidated Tax Savings-Oneida Mining						(503)	503
Interest Expense*						13,527	(13,527)
Total Adjustments	$ (315,833)	---	$ (4,247)	---	---	$13,203	$(8,956)
Company Rate Base	3,588,858						
ALJ Rate Base	$3,273,025						

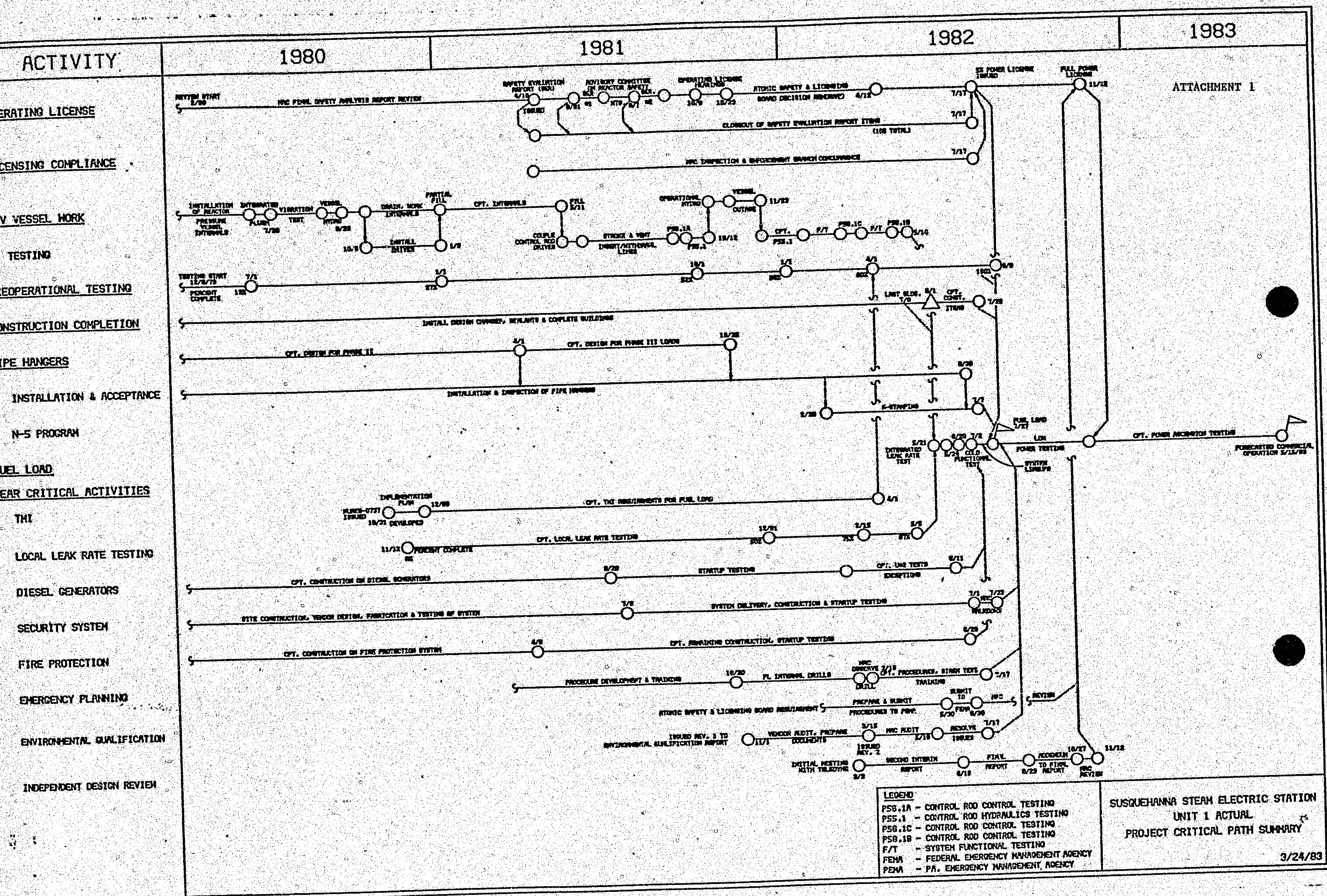
* Interest Expense:

ALJ Rate Base	$3,273,025
Weighted Debt Cost	x 5.14%
ALJ Allowance	168,233
Company Claim	195,414
Reduction in Claim	27,181
Tax Factor	x .497674
Increase in Taxes	$ 13,527

TABLE VII

INCOME SUMMARY
($000)

	Pro Forma Present Rates	ALJ Adjustment	Adjusted Present Rates	Revenue Increase	Total Allowable Revenues
Operating Revenues	$1,186,279	---	$1,186,279	$ 201,652	$1,387,931
Deductions:					
O&M Expenses	633,735	(4,247)	629,488	---	629,488
Depreciation	107,731	---	107,731	---	107,731
Taxes, Other	46,243	---	46,243	4,033	50,276
Income Taxes	87,610	13,203	100,813	98,350	199,163
Total Deductions	875,319	8,956	884,275	102,383	986,658
Income Available	$ 310,960	$ (8,956)	$ 302,004	$ 99,269	$ 401,273
Rate Base					$3,273,825
Rate of Return					12.26%


ACTIVITY
1980
1981
1982
1983
ATTACHMENT 1
ERATING LICENSE
CENSING COMPLIANCE
V VESSEL WORK
TESTING
EOPERATIONAL TESTING
NSTRUCTION COMPLETION
IPE HANGERS
INSTALLATION & ACCEPTANCE
N-5 PROGRAM
UEL LOAD
EAR CRITICAL ACTIVITIES
THI
LOCAL LEAK RATE TESTING
DIESEL GENERATORS
SECURITY SYSTEM
FIRE PROTECTION
EMERGENCY PLANNING
ENVIRONMENTAL QUALIFICATION
INDEPENDENT DESIGN REVIEW
LEGEND
PSG.1A - CONTROL ROD CONTROL TESTING
PSS.1 - CONTROL ROD HYDRAULICS TESTING
PSG.1C - CONTROL ROD CONTROL TESTING
PSG.1B - CONTROL ROD CONTROL TESTING
F/T - SYSTEM FUNCTIONAL TESTING
FEMA - FEDERAL EMERGENCY MANAGEMENT AGENCY
PEMA - PA. EMERGENCY MANAGEMENT AGENCY
SUSQUEHANNA STEAM ELECTRIC STATION
UNIT 1 ACTUAL
PROJECT CRITICAL PATH SUMMARY
3/24/83

APPENDIX A

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-822169
Pennsylvania Power & Light Company	:	

STIPULATION OF PARTIES
WITH RESPECT TO CERTAIN DEPRECIATION ISSUES

Pennsylvania Power & Light Co. (PP&L) and the Trial Staff of the Pennsylvania Public Utility Commission (Staff), participants in the above-captioned proceeding and at individual complaint dockets which have been consolidated therewith, (hereinafter jointly referred to as parties), hereby agree and stipulate for the record as follows:

1. On November 22, 1982, PP&L filed Supplement No. 2 to Tariff Electric - Pa. P.U.C. No. 199 to become effective January 22, 1983. Based upon a test year ending July 31, 1983, this tariff supplement proposed, inter alia, a rate increase in the amount of about $315,000,000.

2. Subsequent to said filing, the staff of the Pennsylvania Public Utility Commission (Commission) engaged in extensive review of the filing and its supporting data which included, inter alia, responses to the Commission's filing regulations, direct testimony and related exhibits. In addition, PP&L and Staff participated in discovery by way of telephone discussions, conferences and both informal and formal data requests and responses thereto.

3. By Order dated January 30, 1983, the Commission instituted an investigation of Supplement No. 2 and the supplement was suspended by operation of law for seven months until August 22, 1983.

4. A pre-hearing conference was held before the presiding Administrative Law Judge on January 20, 1983.

5. Formal and informal discovery has been pursued with respect to annual and accrued depreciation. PP&L has provided responses to data requests and formal interrogatories relating to these issues.

6. At the initial pre-hearing conference, the Administrative Law Judge conducted a general discussion in which the possibilities of settling non-Susquehanna issues were explored in accordance with the Commission's rules of practice. The parties undertook to give consideration to such possibility and, while at all times the parties have continued to move ahead vigorously with the case, settlement discussion and negotiation has been conducted among the parties.

7. The parties have reached agreement with respect to all annual and accrued depreciation issues except Modified Sinking Fund depreciation as proposed by PP&L to be used for its Nuclear Production plant. The parties are in full agreement that it would be in the public interest of PP&L's customers generally to resolve the depreciation issues in the instant proceeding in accord with such agreement. This Stipulation represents the agreement and proposed settlement of such issues by the parties which are as follows:

(a) The evidence of record establishes that, pursuant to the direction of the Commission in its Order of August 26, 1976 at R.I.D. No. 221 PP&L initiated the use of a life-span depreciation system applicable to its electric Steam Production and Other Production generating plant (hereinafter referred to as generating plant).

(b) The Commission's Order at R.I.D. No. 221 provided that PP&L should continue to employ the so-called average service life depreciation system for hydroelectric generation, transmission, distribution, and general plant.[1/]

(c) Following the proceedings at R.I.D. No. 221 and pursuant to its understanding of the Commission's directive, PP&L established its "PP&L Reserve" for its generating plant as of December 31, 1975. The "PP&L Reserve" was established by pro-rating the total amount of its book reserve over the accounts at each generating

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1/ Prior to this Order, PP&L had employed the whole-life, straight line, account group depreciation system for all electric plant. This system employs average service life and retirement dispersion parameters based upon analyses of actual retirement experience of facilities and engineering judgement. The resultant parameters were applied to investment in plant by account irrespective of location or vintage.

station in the same proportions as the calculated theoretical reserve calculation.

(d) In its Order of January 31, 1981, at Docket No. R-80031114, the Commission approved the Stipulation of Parties with Respect to Certain Depreciation Issues which contained the following points:

(i) The "PP&L Reserve" was adopted as the appropriate reserve to use for book and rate making purposes for PP&L. Additional components of the "PP&L Reserve", the "True-Up Process" and "Review Process", were incorporated into the "PP&L Reserve" to the satisfaction of all parties.

(ii) Specific life spans were established with respect to certain generating plant.

(iii) The depreciation study supporting all electric plant other than generating plant represented a reasonable methodology and produced proper average service lives and retirement dispersions by account for Hydroelectric Generation, Transmission, Distribution and General Plant.

(iv) The parties agreed that PP&L's existing unique record keeping and data control and retrieval systems and capabilities make the use of the "PP&L Reserve" system both the most practicable and most reasonable for PP&L.

(v) PP&L's filing in Docket No. R-80031114 proposed that, since the "PP&L Reserve" reasonably represents recovery of investment, it is the proper reserve to be used as the deduction applicable to an original cost rate base.

(e) At all times subsequent to the Commission's Order of January 31, 1981, at Docket No. R-80031114, PP&L has continued to charge annual depreciation in strict accordance with the parameters set out in that order. Its records specifically disclose the effect upon the "PP&L Reserve" of actual generating plant additions, transfers, retirements and annual accruals. Therefore, at July 31, 1982 the "PP&L Reserve" represents a reasonable measure of the recovery of investment in generating plant at that date. The projection of such reserve to July 31, 1983, used in this proceeding represents a reasonable estimate of such recovery at that date.

(f) The parties agree that, together with the approval and adoption of the "PP&L Reserve", the specific life spans with respect to certain generating plant shall be:

(i) The estimated deactivation date of Sunbury Diesel and Sunbury Combustion Turbine will be the year 2000. This coincides with the deactivation date of the Sunbury S.E.S. and effectively results in a life span of approximately 33 years for the diesel units and 29 years for the combustion turbine units.

(ii) The estimated deactivation date of the Suburban Combustion Turbine will be the year 1995. This more closely coincides with other combustion turbine locations and effectively results in a life span of 25 years for this power production unit.

(iii) All other estimated deactivation dates will be accepted as filed by PP&L in this proceeding.

(iv) All estimated deactivation dates will be subject to review in any subsequent rate filings.

(g) The parties agree that the interim retirement study which developed the interim retirement curves used in this case will be accepted as filed by PP&L in this proceeding. These curves will be subject to review in any subsequent rate filing.

(h) The parties agree that the total annual depreciation expense, exclusive of that relating to the Susquehanna nuclear plant and contractor retentions, to be accepted as proper in this case is $97,448,000.

(i) The parties agree that the "PP&L Reserve" for steam and other generating plant in the amount of $423,405,825 is accepted as the proper reserve to be deducted from electric plant in service July 31, 1983 to arrive at the steam and other production net plant in service component of PP&L's original cost rate base.

(j) As set forth in subparagraph (b), above, PP&L employs the whole-life, straight line, account group depreciation system for all electric plant other than generating plant. The parties agree that:

(i) PP&L's depreciation study represents a reasonable methodology and that it produces proper average service lives and retirement dispersions by account for Hydroelectric Generation, Transmission, Distribution and General Plant.

(ii) The total book reserve for such plant at July 31, 1983 is the amount of $456,889,998 and is accepted as the proper reserve to be deducted from such electric plant in service to arrive at the associated net plant in service component of PP&L's original cost rate base.

(iii) Due to PP&L's existing unique record keeping and data control and retrieval systems and capabilities, the use of the Book Reserve for all electric plant other than generating plant is the most practicable and most reasonable for PP&L.

(iv) The depreciation reserve as it applies to this plant shall be initially computed for each account by taking its pro rata share of the

December 31, 1982 functional reserve balance. The pro rata share shall be a function of the calculated theoretical reserve as calculated at December 31, 1982 using the lives and dispersions presented in this case.

(v) The book depreciation reserve activity and balances will be monitored on an annual basis.

(k) The parties recognize that the settlement of depreciation issues on a fair, reasonable and just basis as proposed by this Stipulation is in the public interest in that it will serve to promote the expeditious processing of the proceedings and will avoid the expenditure of the time and costs required for briefing and argument and the unnecessary expenditure of resources, both human and material.

(l) This Stipulation, resulting as it has from formal and informal discovery, reference to the evidence of record and serious negotiation, is proposed by the parties to settle all depreciation issues with the exception of Modified Sinking Fund depreciation as proposed by PP&L to be used for its Nuclear Production plant. These issues, in summary, are:

(i) Continued use of the "PP&L Reserve" and its components, the "True-Up Process" and "Review Process", as it applies to generating plant.

(ii) Approval of all life spans for generating plant as presented.

(iii) Approval of the interim retirement study as presented.

(iv) Approval of the depreciation study as it relates to Hydroelectric Generation, Transmission, Distribution and General Plant.

(v) Approval of the total annual depreciation expense as claimed, exclusive of that related to the Susquehanna Steam Electric Station and contractor retentions.

(vi) Approval of the use of the Book Reserve as the proper reserve to be used in rate making for Hydroelectric Generation, Transmission, Distribution and General Plant.

(m) This Stipulation is proposed without any admission or prejudice to any positions which any party might adopt during subsequent proceedings, at this or any other docket, if this Stipulation is rejected by the presiding Administrative Law Judge or the Commission.

(n) In the opinion of the parties, this Stipulation is just, reasonable and lawful and is fully supported by the testimony and exhibit evidence of record. The evidence of record at the time of the execution of the Stipulation, which the parties submit fully supports the same, is incorporated as a part hereof by reference.

(o) The parties hereby agree to request that the presiding Administrative Law Judge Joseph J. Klovekorn approve this Stipulation, incorporate it in the record and, in his decision, recommend it to the Commission for approval for the purposes of this proceeding and with regard to the rates of PP&L as though the Commission had made specific findings after hearings on these depreciation issues.

(p) The parties hereby agree to request that the presiding Administrative Law Judge Joseph J.

Klovekorn and the Pennsylvania Public Utility Commission order that in the future PP&L shall maintain the "PP&L Reserve," incorporating the associated "True-Up Process" and "Review Process," in strict accordance with the parameters set out in the Stipulation so that PP&L's records will specifically disclose the effect upon the "PP&L Reserve" of actual generating plant additions, transfers, retirements, and annual accruals. Also, PP&L shall maintain the Book Reserve for hydroelectric, transmission, distribution, and general plant as well as a monitoring process in strict accordance with the parameters set out in this stipulation so that PP&L's records will specifically disclose the effect upon the Book Reserve of actual plant additions, transfers, retirements, and annual accruals.

THIS STIPULATION is conditioned upon and subject to the acceptance of the Administrative Law Judge and the Pennsylvania Public Utility Commission. Further, recognizing that this Stipulation results from discovery and discussion and reflects compromises by both sides, if it is not accepted by Administrative Law Judge and the Commission, without modification, then no inference adverse to any party shall be drawn therefrom. Finally, it is expressly understood by the parties that this Stipulation is conditional and shall have no force or effect unless adopted by the Commission.

Signed and Sealed By The Parties Aforesaid this 28th day of April, 1983.

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______________________ ______________________

APPENDIX C

PENNSYLVANIA POWER & LIGHT COMPANY
COST-OF-SERVICE STUDY
YEAR ENDING JULY 31,1983
AVERAGE AND EXCESS METHOD
NCP FOR PRIMARY
STAFF PROPOSED RATES (000'S DOLLARS)

	TOTAL	RESID	GS1	GS3	LP4	LP5	LP6
TOTAL REVENUE	1,482,347	603,033	102,655	274,888	177,047	58,493	166,358
TOTAL EXPENSES	1,026,077	430,791	68,460	181,972	119,835	40,100	116,398
RETURN	456,270	172,242	34,195	92,916	57,211	18,394	49,960
RATE BASE	3,588,858	1,654,596	217,996	574,100	367,180	125,660	363,266
RATE OF RETURN	12.71%	10.41%	15.69%	16.18%	15.58%	14.64%	13.75%

Exhibit KE-2 (   )
Schedule 2
Page 1 of 2

PENNSYLVANIA POWER & LIGHT COMPANY
COST-OF-SERVICE STUDY
YEAR ENDING JULY 31,1983
AVERAGE AND EXCESS METHOD
NCP FOR PRIMARY
STAFF PROPOSED RATES (000'S DOLLARS)

	GH	STR LGHT
TOTAL REVENUE	78,331	21,541
TOTAL EXPENSES	53,387	15,133
RETURN	24,944	6,408
RATE BASE	232,255	53,805
RATE OF RETURN	10.74%	11.91%

Exhibit KE-2 ( )
Schedule 2
Page 2 of 2

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Uniform Cover and Calendar Sheet

1. REPORT DATE: July 21, 1983
2. BUREAU AGENDA NO. JUL-83-ALJ-187
3. BUREAU: ALJ
4. SECTION(S):
5. PUBLIC MEETING DATE: July 29, 1983
6. APPROVED BY: William H. Smith
   Director: 7-6108
   Supervisor:
7. MONITOR: Commr. Johnson
8. PERSON IN CHARGE: ALJ Klovekorn 8-325-2105
9. DOCKET NO: R-822169, et al.
10. (a) CAPTION (abbreviate if more than 4 lines)
    (b) Short summary of history & facts, documents & briefs
    (c) Recommendation

(a) Pennsylvania Public Utility Commission, et al. v. Pennsylvania Power & Light Company

(b) On November 22, 1982, PP&L filed for a $315 million rate increase. The request was suspended by operation of law until August 22, 1983. On December 3, 1982, the Commission instituted an investigation at R-822169. One hundred eighty formal complaints were filed and consolidated with the rate investigation for the purpose of hearing, briefing and disposition. Twenty-nine days of hearings and twelve public input hearings were held.

(c) Judge Klovekorn issued a Recommended Decision increasing rates by approximately $201,650,000 annually.

Recommended Decision served: June 28, 1983.

See attached sheet for Exceptions and Reply Exceptions.

DOCKETED
AUG 15 1983

11. MOTION BY: CommissionerChm. Taliaferro
    SECONDED: CommissionerJohnson

Commissioner Cawley - Yes
Commissioner
Commissioner

CONTENT OF MOTION: After polling the Commission on various issues, including Original Cost Measure of Value, Rate of Return, Operating Expenses and Depreciation, and Taxes, the matter be postponed to Public Meeting August 12, 1983 for further polling.

DOCUMENT
FOLDER

EXCEPTIONS FILED BY:

St. Regis Corporation, July 13, 1983.
Susquehanna Alliance and CEPA, July 13, 1983.
Pennsylvania Power & Light Company, July 13, 1983.
Lehigh Valley Power Committee, July 13, 1983.
U.S. Department of Defense and other affected Executive Agencies (DOD), July 13, 1983.
The City of Harrisburg, July 13, 1983.
Commission Trial Staff, July 13, 1983.
Bethlehem Steel Corporation, July 13, 1983.
Office of Consumer Advocate, July 13, 1983.
Milton Manufacturing Company, Crown American Corporation and Hess's Department Stores, Inc., July 13, 1983.

NO OTHER EXCEPTIONS TIMELY FILED.

REPLY EXCEPTIONS FILED BY:

St. Regis Corporation, July 20, 1983.
Branch 39 of the Utility Consumers Union of CEPA and Susquehanna Alliance, July 20, 1983.
Milton Manufacturing Company, Crown American Corporation and Hess's Department Stores, Inc., July 20, 1983.
Eastern Penn Energy Association, July 20, 1983.
Office of Consumer Advocate, July 20, 1983.
Pennsylvania Power & Light Company, July 20, 1983.

DUE TO THE VOLUMINOUS AMOUNT OF EXCEPTIONS AND REPLY EXCEPTIONS FILED, THEY ARE NOT ATTACHED TO THIS PUBLIC MEETING PACKAGE. HOWEVER, COPIES OF ANY OF THESE DOCUMENTS MAY BE SEEN IN ROOM G-7A.