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June 16, 1995

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John G. Alford, Secretary
Pennsylvania Public Utility Commission
New Filing Section, Room B-20
North Office Building
Commonwealth & North Streets
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
Pennsylvania Power & Light Company
Docket No. R-00943271

Dear Secretary Alford:

Enclosed for filing in the above-captioned proceeding are an original and nine copies of the Initial Brief of Pennsylvania Power & Light Company. Also enclosed is an additional copy of the Company's Brief which we request that you date stamp and return to us as evidence of filing.

As indicated on the attached Certificate of Service, copies of the Brief have been served on Administrative Law Judge Robert A. Christianson and all active parties of record.

Sincerely,

Thomas P. Gadsden

Thomas P. Gadsden
Counsel for Pennsylvania
Power & Light Company

DOCUMENT FOLDER

TPG:jod
Enclosure

cc: Honorable Robert A. Christianson
Certificate of Service

ORIGINAL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
v.	:	Docket No. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

INITIAL BRIEF OF RESPONDENT

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKETED
JUN 19 1995

Before Administrative Law Judge
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I. INTRODUCTION

Major electric base rate proceedings inevitably involve a myriad of ratemaking issues, claims and proposed adjustments. This case is no exception. The parties will address these matters in their Briefs, and the Administrative Law Judge will resolve them in his Recommended Decision. However, it is important that the examination of these detailed individual issues not overshadow the Company's overall need for fair and adequate rate relief in this proceeding.

First, the Company has not filed for a general base rate increase for over ten years.[1/] Since its last base rate case, the general rate of inflation has increased by over 30% and the Company has incurred hundreds of millions of dollars of increased plant investment and operating expenses. The Company has been able to offset these cost increases, to some extent, by aggressively refinancing high-cost debt and preferred stock, promoting increased economic development in its service territory and undertaking aggressive cost cutting measures. These measures alone, however, are no longer adequate, and the Company requires substantial rate relief to recover its increased costs of operation, to maintain its current A- bond rating and to earn a fair return on its investment to serve the public.

Second, rate relief is required to ensure that today's customers pay today's cost of service. A number of the Company's

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[1/] Indeed, the Company's overall rates today (base rates plus ECR) are virtually the same as they were in 1985.

claims in this case, e.g., a full return on its investment in Susquehanna Unit 2, fossil and nuclear decommissioning, shortening of fossil plant depreciation lives, levelized depreciation for Susquehanna, and the adoption of SFAS 87, SFAS 106 and SFAS 112 for ratemaking purposes, are specifically designed to ensure that current rates reflect the true cost of serving current customers and to avoid unfair cost shifting to future customers. For example, the Company's decommissioning claims seek to assign the true cost of service from the Company's generating units to those customers who receive service from these units. Similarly, the Company's proposal to levelize depreciation of the Susquehanna Plant seeks to establish a more accurate measure of the annual cost of that plant and avoid annual rate filings which might otherwise be necessary to reflect the changes in annual depreciation expense inherent in the current modified sinking fund method.

Third, rate relief is required for the Company to continue to provide safe, reliable and high quality service to its customers. The Company's track record in this area is impressive by any standard. Indeed, no party has raised any challenge regarding the quality or reliability of the Company's service.

The Company is particularly proud of the extraordinary operating record of its Susquehanna Plant. The Plant has achieved an annual capacity factor greater than 70% in every year since 1987. In three of these seven years, Susquehanna's annual capacity factor exceeded 80%. PP&L has calculated that, during the 1987-1993 period, its customers realized additional energy cost savings of approximately $140 million as a direct result of the Company's ability to operate Susquehanna at a capacity factor above 70%. The Susquehanna Plant is recognized by the NRC, industry organizations and the investment community as an efficient, well-run facility.

Beyond the basics of providing reliable service and highly efficient operations, the Company has been a leader in conservation and load management programs, economic development initiatives and social programs. The Company's economic development initiatives have aided in attracting 470 new companies during the previous five-year period, which has resulted in the creation of 29,544 new jobs in its service area. In addition, PP&L's work with customers in industry retention has assisted in 373 industry expansions totalling 17,606 new jobs over the same period. Currently, a significant number of new industrial firms are indicating an interest in PP&L's service area as a site for their new facilities.

PP&L also has been a consistent leader among Pennsylvania utilities in developing social programs for its customers. Since the late 1970's, the Company has implemented a variety of programs and services designed to serve the needs of its communities and customers, particularly low-income customers. The Company's major customer needs programs include the Customer

Assistance and Referral Evaluation Services, Operation HELP, and Winter Relief Assistance Program. In addition, the Company has proposed a package of additional social initiatives in this case designed to assist in meeting customer and community needs in its service territory.

The Company believes that these various economic development, load management and community service activities are beneficial to the Company, its customers and the communities it serves. To continue these programs, the Company must receive fair and adequate rate relief in this proceeding.

Finally, the Company has proposed a modest restructuring of its rates to position itself for increased competition. This increase in competition is well documented and undoubtedly is the most important single issue facing the electric utility industry and the Company today.

To address these concerns, the Company has determined that it must convert from a "shotgun" approach to a "rifle" approach in its economic development and competitive rate programs. For example, in place of large interruptible service discounts available to all customers, the Company has established a Price Response Service and the Competitive Rate Rider, which will enable it to respond to an individual customer's needs without providing windfall savings to other customers who do not require assistance. This is clearly the best way for the Company to meet competition, promote economic development and protect the interests of all of its customers.

The Company believes that its rate filing strikes a reasonable balance between customer and shareholder interests and should be approved. The opposing parties' response to the Company's initiatives has been disappointing, at best. They have opposed, in "knee jerk" fashion, virtually every one of the Company's innovative and creative ratemaking proposals and have proceeded with only one apparent objective -- to produce the lowest possible short-term rates, regardless of the adverse impact on the Company's financial condition, its ability to provide reliable, high quality service and its ability to implement economic development, load management and social programs.

The proposals of the Office of Consumer Advocate ("OCA") are particularly disturbing. If accepted, they would produce a staggering rate decrease of approximately $66 million. As explained in detail below, most of the OCA proposals are clearly inconsistent with well-established Commission precedent, would result in a massive shifting of cost from current customers to future customers, would jeopardize the Company's current A- bond rating and would not permit the Company to earn anything approaching a fair return on its investment. The OCA's excess capacity adjustment is especially disappointing in its attempt to "change the rules of the game" and ignore the clear guidelines established in the Company's last base rate proceeding for the full inclusion of Susquehanna 2 in rates.

The revenue requirement proposals presented by the other parties in this proceeding, while not as extreme as the OCA's recommendation, are just as negative in their overall approach and results. The Company urges the Commission to take a broader view and establish rates in this proceeding that will promote the long-term success of PP&L, its customers and the communities it serves.

With respect to rate structure issues, each of the opposing parties, as expected, has advocated proposals to protect its own interests at the expense of other classes of customers. However, the proposals presented by the industrial customers in this case are particularly disturbing.

PP&L has made an outstanding effort to promote economic development in its service territory and to maintain competitive rates for industrial customers. These efforts include a package of economic and industrial development initiatives approved by the Commission in the early 1990s and funded solely by shareholders to date. These initiatives included a 20% rate decrease in 1991 to industrial customers selecting interruptible service.

In spite of these efforts, the industrial customers have aggressively opposed PP&L's attempt to restructure its rates, particularly those proposals addressing interruptible rates. Under the Company's proposal in this case, interruptible customers will pay rates slightly below the rate level set in 1985. Yet, the industrial customers insist on mischaracterizing the Company's recommendation as a massive 28% increase in rates.

Moreover, in criticizing the Company's interruptible rate proposal, the industrial customers completely ignore all of the other efforts undertaken by PP&L to develop competitive rates and promote economic development. The net result of the positions advanced by the interruptible service customers would be to encourage wide-spread installation of self-generation on the Company's system and a massive shifting of costs to residential customers, neither of which is in the public interest.

If the opposing parties' proposals were adopted in this case, PP&L's efforts to move forward in constructive partnership with its customers would be frustrated, and its objectives for this rate case, all of which are in the public interest, could not be achieved. The Company submits that this is an unreasonable result and does not reflect a rational and reasoned approach to public utility ratemaking. The Company's proposals in this case are fully supported by the record evidence and should be approved.

II. STATEMENT OF THE CASE

A. Description Of The Company

The 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.

By its Order entered February 10, 1995, the Public Utility Commission approved the Company's Application to form a Holding Company structure; and at PP&L's Annual Meeting of Shareowners held on April 26, 1995, that proposal was approved. Consequently, effective April 27, 1995, all of the outstanding Common Stock of PP&L was exchanged for and converted into Common Stock of PP&L Resources, Inc. ("Resources"), thus making Resources the parent company of PP&L

PP&L presently serves a 10,000 square mile territory encompassing 29 counties in central-eastern Pennsylvania. This territory is in the heart of the nation's largest industrial and commercial market area and also contains extensive agricultural regions, as well as over 800 major communities, including the Cities of Allentown, Bethlehem, Harrisburg, Lancaster, Scranton, Wilkes-Barre and Williamsport. PP&L serves approximately 1,207,606 customers in its authorized service territory and expects to serve 1,228,047 by September 30, 1995.

In addition to its retail operations, the Company supplies wholesale electric service to 16 Pennsylvania boroughs. It also provides electric service to the Luzerne Electric Division of UGI Corporation under a firm power supply agreement and provides energy to several other utilities. These wholesale services are subject to the regulatory jurisdiction of the Federal Energy Regulatory Commission (the "FERC").

The Company owns and operates two nuclear units (jointly owned by PP&L (90%) and Allegheny Electric Cooperative, Inc. (10%)), five fossil-fueled steam and two hydroelectric generating stations, as well as a number of combustion turbine and diesel units located throughout its system. 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 electric utilities (PP&L St. 9, p. 3). The Company also owns one-third of the Safe Harbor Hydro Station located along the Susquehanna River in Conestoga, Pennsylvania. The Company's total owned and leased generation resources at September 30, 1994 were 8,543 Megawatts ("Mw") (PP&L St. 9, p. 2).

The system consists of an integrated power transmission system with more than 1,100 miles of transmission line operating at 230,000 volts or higher, and more than 50,000 miles of distribution line operating at less than 230,000 volts (PP&L St. 9, p. 3).

The Company operates its generation and transmission facilities as a part of the Pennsylvania-New Jersey-Maryland

("PJM") Interconnection (PP&L St. 9, p. 3). The transmission facilities provide the electric links between the PP&L system and the systems of its neighboring electric utilities. The PJM Interconnection consists of PP&L and other electric utility systems in the states of Pennsylvania, New Jersey, Maryland, Delaware, Virginia and the District of Columbia (PP&L St. 9, p. 8). The PJM member companies 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. 9, p. 8). This operation is governed by the PJM Interconnection Agreement, a rate schedule subject to the jurisdiction of the FERC.

B. <u>History Of The Proceeding</u>

On December 30, 1994, PP&L filed Supplement No. 50 to Tariff Electric - Pa. P.U.C. No. 200 ("Supplement No. 50"), requesting an increase in total annual base rate operating revenues of $261,635,000, or approximately 11.7% over the level of revenues anticipated for the future test year ending September 30, 1995. The principal purposes of this filing are to bring PP&L's rates for retail electric service in line with the cost of providing that service and to position the Company's rates to respond to an increasingly competitive market for electric power. The requested increase is necessary to cover the Company's cost of service including a fair return on its capital investment, to address future known changes in several aspects of the Company's business and to avoid future financial deterioration.

By Order entered January 27, 1995, the Pennsylvania Public Utility Commission (the "Commission") instituted a formal investigation at Docket No. R-00943271 to determine the lawfulness, justness and reasonableness of the Company's existing and proposed rates. Supplement No. 50 was thereby suspended by operation of law for a period of up to seven months, or until September 28, 1995. Thereafter, the matter was initially assigned to Administrative Law Judge Michael C. Schnierle but later reassigned to now Acting Chief Administrative Law Judge Robert A. Christianson for hearing and the issuance of a Recommended Decision.

The Company has been served with 145 formal Complaints filed against the proposed rate increase. However, of that number, only a dozen Complainants actively participated in this case, including the Office of Consumer Advocate (the "OCA"), the Office of Small Business Advocate (the "OSBA"), the Pennsylvania Power & Light Industrial Customer Alliance ("PPLICA"), the U.S. Department of Defense (the "DOD"), Central Eastern Pennsylvania Fuel Oil Dealers ("CEPFOD"), The Commission on Economic Opportunity (the "CEO") and Eric J. Epstein. Petitions to Intervene were filed by M&M/Mars, Inc., Bethlehem Steel Corporation, University/College Coalition ("UCC") and the Sierra Club. The Commission's Office of Trial Staff (the "OTS") submitted a Notice of Appearance and participated fully in this proceeding.

Accompanying Supplement No. 50, the Company filed the extensive and detailed supporting information required by the Commission's regulations, including the prepared written testimony and exhibits of its 14 initial witnesses.

A Prehearing Conference was held in Harrisburg on March 7, 1995. Thereafter, 16 days of evidentiary hearings were held in Harrisburg, producing approximately 2,400 pages of transcript. In addition, 11 public input hearings were held throughout PP&L's service territory -- in the afternoon and evening of March 30, 1995 in Harrisburg; in the afternoon and evening of March 31, 1995 in Lancaster; in the evening of April 3, 1995 in Williamsport; in the afternoon of April 4, 1995 in Scranton and in the evening in Wilkes-Barre; in the afternoon of April 5, 1995 in Hazleton and in the evening in Pottsville; and in the afternoon of April 6, 1995 in Bethlehem and in the evening in Allentown.

During the course of the hearings, PP&L submitted 32 written statements of direct and rebuttal testimony and numerous accompanying exhibits prepared by 17 witnesses (a schedule setting forth those statements and exhibits has been attached hereto as Appendix A). Supplementing this testimony, exhibits and the December 30, 1994 filing, the Company responded to over 1,000 interrogatories and data requests. The OTS, OCA, OSBA, PPLICA, UCC, Bethlehem Steel, the Sierra Club, DOD, CEO, CEPFOD, the Lancaster Chamber of Commerce and Eric J. Epstein submitted 49 written statements and numerous exhibits.

The hearings in this matter concluded on May 26, 1995. The case is now ready for decision.

III. MEASURES OF VALUE/RATE BASE

The Company's claim for rate relief in this case is based upon data for a future test year ending September 30, 1995 (see Appendix B and PP&L Ex. Future 1 - Revised). Additionally, in accordance with the Commission's regulations, PP&L has provided extensive data for the historic test year ended September 30, 1994. However, unless specifically noted otherwise, all figures referenced herein will be based upon future test year data only.

PP&L's final claimed rate base of $5,017,708,000 (Appendix B) consists of the depreciated original cost of its utility plant in service at September 30, 1995, together with rate base additions and deductions made in accordance with accepted ratemaking procedures, as explained hereafter.

A. Original Cost Utility Plant In Service

To develop the future test year level of plant in service, the original cost of plant to be constructed or acquired by PP&L during the twelve months ending September 30, 1995 was added to the original cost of plant recorded on its books at September 30, 1994, and the original cost of plant to be retired during the twelve months ending September 30, 1995 was subtracted (PP&L St. 3, pp. 8-9; PP&L Ex. Future 1, Sch. C-2).[2/] The Company's

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[2/] The original cost of the Company's utility plant in service at the end of the historic test year was taken directly from the Company's continuing property records, which are periodically reviewed and audited by the FERC's audit staff and the Commission's Bureau of Audits (PP&L St. 3, pp. 6-7).

final claim for the original cost of plant in service at September 30, 1995 is $8,196,706,000 (Appendix B; PP&L Ex. Future 1 - Revised), Sch. C-1). That amount includes the original cost of the Company's generating stations exclusive of the portions thereof that are used to furnish FERC-jurisdictional service. Witnesses on behalf of the OTS and the OCA have proposed adjustments to deny the Company a return on a portion of its investment in generating resources that they contend represents "excess capacity." For the reasons set forth hereafter, those proposed adjustments should be rejected.

1. Usefulness Of PP&L's Generating Capacity

Under well-established principles, a utility is entitled an opportunity to earn a fair return on its investment in facilities dedicated to public service, provided that the investment was prudent when made and that the facilities in question will be "used and useful" during the period when new rates are to be in effect. See Pa. P.U.C. v. Philadelphia Electric Co., 54 Pa. P.U.C. 220, 225 (1980), aff'd, 61 Pa. Cmwlth. 325, 433 A.2d 620 (1981).

In this proceeding PP&L submitted substantial, affirmative evidence establishing that all of its electric generating facilities are "used and useful." The OTS and the OCA have contested that position, contending that a portion of PP&L's existing capacity is not needed to maintain system reliability and, therefore, should be found to be "physical" excess capacity.

In addition, the OCA asserts that Susquehanna Steam Electric Station Unit No. 2 ("SSES 2" or "Unit 2"), when measured against the current and prospective market cost of power, represents "economic" excess capacity. As discussed below, these arguments are without merit and should be rejected.

a. Background

When PP&L first claimed the costs of SSES 2 in rates in 1984, the Commission determined that SSES 2 constituted excess capacity because it was not then needed to satisfy customers' demands for electricity. See Pa. P.U.C. v. Pennsylvania Power & Light Co. 59 Pa. P.U.C. 332 (1985), aff'd, 101 Pa. Cmwlth. 370, 516 A.2d 426 (1986) (the "Unit 2 Case"). More specifically, the Commission found that 22% was a reasonable reserve margin for ratemaking purposes and that PP&L could maintain that level of reserves without Unit 2. While the economics of SSES 2 were also extensively litigated, the Commission concluded that the evidence of future benefits was too speculative and distant in time to have any probative value.

Based on its excess capacity finding, the Commission denied the Company an equity return on its investment in SSES 2, reasoning that such a remedy resulted in a fair sharing of risks and rewards between customers and shareholders. That adjustment had the effect of reducing PP&L's requested rate increase by $161 million and has been in place ever since. The Commission made it clear, however, that its adjustment could and, under the appropriate circumstances, would be reconsidered in subsequent proceedings:

> [W]e have made continuation of our excess capacity adjustment contingent on either one of two alternatives: if the Company can show that SSES 2's net economic benefits have begun to outweigh its net costs, or that its capacity is no longer excess relative to system reliability, then the Company may take appropriate steps to seek a modification of this adjustment.

Ibid, p. 351.

In the ten years that have elapsed since the Unit 2 Case, SSES 1 and 2 have operated exceptionally well. As noted by Mr. George T. Jones, PP&L's Vice President - Nuclear Engineering, SSES' annual capacity factor has exceeded the industry average in each and every year since 1987 and the plant recently set a world record of 286 days of continuous operation of both units (PP&L St. 15-R, p. 3). Because of this outstanding performance, PP&L's customers realized approximately $140 million in additional energy cost savings during the 1987-1993 period alone (PP&L St. 1, pp. 5-6). Indeed, even the OCA's witness, Mr. Kahal, acknowledged that SSES had run very well (Tr. 1596):

> Q. And can we agree that historically, the Susquehanna [Plant] has operated at a 75-80 percent capacity factor?
>
> A. Well, not necessarily in every year, but that's a reasonable characterization I think of its history. And for a nuclear plant, that's a relatively high capacity factor.
>
> Q. So the plant has run pretty well, at least in your judgment?

A. Yes, it has. In that regard, I think the plant has been successful.

Perhaps more importantly, the demands of PP&L's customers for electricity increased substantially during this same period. For example, in 1985 when SSES 2 came on line, the Company's most recent winter peak equalled 5035 Mw; the corresponding figure for this past winter was 6590 Mw. In other words, PP&L's peak demand rose by 1555 Mw, or 610 Mw <u>more</u> than the 945 Mw of capacity that were found to be "excess" in the <u>Unit 2 Case</u>. This is significant because, apart from an extremely cost-effective uprate at SSES, PP&L has not added to the capacity which it owns and operates since SSES 2 was placed in service.

Notwithstanding the foregoing, the OTS and the OCA have recommended substantial excess capacity adjustments in this case. In order to rationalize their proposals, however, both parties were forced to rewrite the rules of the game by (1) arbitrarily lowering PP&L's allowable reserve margin from the 22% figure found reasonable in the <u>Unit 2 Case</u> to 15%-16%; (2) penalizing the Company for having purchased output from Qualifying Facilities ("QFs") in compliance with Federal law; (3) ignoring the value to customers and PP&L's service territory of certain measures undertaken voluntarily by PP&L (e.g. cost-effective capacity uprates, economic development initiatives); and, in the case of the OCA, (4) applying an unworkable, unreasonable and unprecedented market-based "economic benefits" test.

As will be made clear in the discussion which follows, the adoption of an excess capacity adjustment in this case would not only be confiscatory and grossly unfair, but would also create tremendous disincentives for electric utilities in Pennsylvania to act responsibly and in the best long-term interests of their customers.

b. PP&L's Current And Prospective Reserve Margins Are Not Only Reasonable, But Are Considerably Lower Than The Level Found Acceptable By The Commission In The Unit 2 Case

In order to assure reliable, reasonably continuous service, an electric utility must have resources equal to its anticipated peak demands plus a reasonable reserve margin. This is because generating units may be idled when the peak occurs, as the result of forced or maintenance outages, and because actual customer demands may substantially exceed forecasted levels. Indeed, the coincidence of these factors in January 1994 led to rotating blackouts that affected customers throughout the Mid-Atlantic Region.

PP&L's projected reserve margins for the future test year and the first year that new rates are to be in effect are 16.4% and 14.2%, respectively. The derivation of those figures, as well as the corresponding range for the next eight years (1997-2004), was explained by Mr. John F. Sipics (PP&L St. 9), the Company's General Manager - Power Systems Support, and will be briefly summarized below.

During the 1994-1995 winter peak period, PP&L owned or leased 8543 Mw of capacity. By the end of the future test year, that figure will have declined marginally to 8540 Mw as the result of a temporary 48 Mw derate at the Martins Creek Plant and a 45 Mw uprate at SSES 1 (PP&L Ex. JFS-1). For purposes of calculating PP&L's reserve margins, Mr. Sipics made two adjustments to these figures. First, he reduced PP&L's available capacity to reflect its contractual obligation to deliver capacity and energy to Atlantic Electric, Baltimore Gas & Electric and Jersey Central Power & Light.[3] Next, he added back the capacity equivalent value which the Company can realize, at least theoretically, by requesting interruptible customers to reduce their demands during peak periods. As a result of these two adjustments, Mr. Sipics calculated that the net capacity resources available to PP&L at the time of its system peaks would be 7685 Mw and 7679 Mw during the test year and the first year that new rates will be effective (PP&L Ex. JFS-1).

Having established the resources available to PP&L to meet its customers' needs, it is then necessary to project what those requirements will be. To this end, the Company presented Dr. John J. Slivka, PP&L's Manager - Market Research, who sponsored the Company's forecast of customer sales and peak loads (PP&L Ex. JJS-1). In his direct testimony (PP&L St. 6, pp. 3-7),

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[3] Specific details regarding the terms of these firm capacity and energy transactions may be found in Mr. Sipics' direct testimony (PP&L St. 9) at pages 3-4.

Dr. Slivka described the various techniques employed by PP&L to project future demands. Based on his analysis, which was not challenged during the course of this proceeding, Dr. Slivka estimated that PP&L's peak demands would approximate 6605 Mw during the future test year and 6725 Mw the following year (PP&L Ex. JJS-1, p. 4).[4] Comparing these projected demands with the resources available to meet them, as developed by Mr. Sipics, produces the 16.4% and 14.2% reserve margin figures discussed earlier.

No party contests the reasonableness of PP&L's projections of owned and leased capacity resources or its peak load forecast. Rather, the dispute among the parties is over (1) what capacity should be included in an evaluation of the Company's generating requirements and (2) what constitutes an appropriate reserve margin for ratemaking purposes. In short, the OTS and the OCA contend that QF output should be counted as an available capacity resource and that PP&L's allowable reserve margin should be set at 15%-16%. PP&L, on the other hand, believes that QF output purchased after the last unit wa added to the utility's system should be excluded from the analysis for ratemaking purposes and that consideration of all relevant factors fully supports a reserve margin in the 12%-20% range.

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[4] As noted by Mr. Sipics (PP&L St. 9, p. 7), peak load forecasts are based on "normalized" weather and temperature conditions. Consequently, a hotter than "normal" summer or colder than "normal" winter can drive peak demands well above estimated levels.

(1) Treatment Of QF Output

Under Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), utilities are required to purchase the output of QFs without regard to their existing or projected peak loads or reserve margins (PP&L St. 9, p. 12). In compliance with its obligations under PURPA, the Company presently purchases 504 Mw from such non-utility generators.[5] Significantly, and as pointed out by Mr. Sipics (PP&L St. 9, p. 12), virtually all of PP&L's agreements with QFs were executed after SSES 2 was substantially completed.

The treatment of QF output is critical to the outcome of this case. Indeed, if QF output is not included in calculating the Company's available capacity resources, there is no basis for concluding that PP&L has "physical" excess capacity because its reserve margins in the future test year and year after would, for all practical purposes, satisfy the 15%-16% benchmarks proposed by the OCA and the OTS. However, the resolution of this issue also has implications that extend far beyond this proceeding. Stated simply, if the opposing parties' position is adopted, it would, as Dr. William H. Hieronymus observed, send a clear message to all of Pennsylvania's electric utilities to minimize the amount of QF capacity on their systems regardless of other

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[5] That figure is expected to drop slightly, to 474 Mw, in the upcoming year (PP&L Ex. JFS-1).

economic or public policy considerations (PP&L St. 16-R, pp. 29-30).[6/]

PP&L submits that it would be patently unreasonable and confiscatory to deny it a return on otherwise needed plant solely because it was required, by PURPA and the Commission's regulations, to purchase output from QFs. This is not a case where a utility continued to add capacity long after the availability of QF output became known. Rather, as previously noted, PP&L's contracts with QFs were not executed until after its last substantial capacity expansion (SSES 2) was virtually completed and the output from the QFs was not even received until several years later (OCA St. 2, Sch. MIK-11, p. 2). Consequently, if PP&L has any excess capacity, the QFs are unquestionably the cause of that excess.

Moreover, the Commission was well aware at the time that the Company did not need the QF output for capacity purposes, when it accepted contracts based on PP&L's energy-only avoided costs (PP&L St. 16-R, p. 30). As Mr. Sipics explained (PP&L St. 9-R, p. 7), PP&L makes no capacity payments to the QFs. However, for

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[6/] Dr. Hieronymus is a Principal and a Director of Putnam, Hayes & Bartlett, Inc ("PHB"), an economics and management consulting firm. Prior to joining PHB, Dr. Hieronymus worked for the U.S. Army, the Systems Technology Company, where he specialized in cost/benefit analysis, and for Charles River Associates, where he directed that firm's studies of supply, demand, and price forecasting for electricity and electric utility fuels. He has testified in Pennsylvania on capacity-related issues on numerous occasions in the past (PP&L St. 16-R, pp. 1-4).

PJM[7] installed capacity accounting purposes, the Company elected to claim QF output as capacity, thereby maximizing its value for the benefit of PP&L and its customers. It would simply be unfair to now penalize PP&L for a prudent management decision designed to enhance the effective utilization of its resources.

Finally, PP&L has no control over QFs. As OTS witness Metro acknowledged (Tr. 1519), significant changes in fuel prices, such as were experienced in the 1970s and early 1980s, or other factors could render the continued operation of QFs uneconomic. In fact, one of the QFs from which the Company purchases power recently declared bankruptcy (Tr. 1520). While PP&L is not impugning the manner in which QFs have performed to date, their future operation cannot be guaranteed.

In his direct testimony (OTS St. 5, pp. 16-17), OTS witness Metro offered five reasons why he believed QF output should be recognized in a reserve margin calculation. Although Dr. Hieronymus responded to each of those reasons individually (PP&L St. 16-R, pp. 32-33), the essence of Mr. Metro's position may fairly be reduced to the proposition that QF output should be counted "because it's there and can be used". This became readily apparent during the following exchange (Tr. 1521):

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[7] As the Commission is aware, the "PJM", or Pennsylvania-New Jersey-Maryland Interconnection, is a regional power pool spanning the Mid-Atlantic Region of which PP&L and several other Pennsylvania electric utilities are members. PP&L's relationship with the PJM, and its impact on the Company's reserve requirements, will be explored in the following Sections of this Initial Brief.

Q. Mr. Metro, if PP&L were forced to sign up another 500 megawatts of QF power tomorrow, would it be your recommendation that the company be denied a return on an additional 500 megawatts?

A. If the company was forced to buy 500 megawatts, yes, it would be my testimony that it would be in excess.

Q. If Congress passed a law next year that required the company to buy 1,000 megawatts of power from the Tennessee Valley Authority, would it be your recommendation that we throw that onto the pile and deny the company a return on another 1,000 megawatts of power?

A. Yes.

Q. Doesn't that strike you as a bit unfair?

A. No.

The capriciousness of Mr. Metro's position is self-evident. Taken to the extreme, one could envision the anomalous situation in which PP&L's entire mix of generating resources was systematically displaced by capacity that it did not need and did not want, leaving the Company with no return on its investment in production facilities. Contrary to Mr. Metro's view, this not only would be unfair, it would be confiscatory and raise serious constitutional concerns.

Like Mr. Metro, OCA witness Kahal asserted that QF output should be included in the analysis because it was the "fact" of excess capacity, and not the cause, that mattered (OCA St. 2, p. 12).[8] Mr. Kahal, based on the advice of the OCA, further

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[8] Mr. Kahal later conceded that the cause of excess capacity was an appropriate consideration in determining the ratemaking adjustment to be made (Tr. 1606).

contended that his treatment of QF output was consistent with Section 1323(c) of the Code (66 Pa.C.S. § 1323(c)), which, by its terms, creates an eight-year window during which the Commission cannot include QF output in determining whether a utility has excess capacity (OCA St. 2, pp. 12-13). Because the eight-year window has closed as to all of the Company's QF output, Mr. Kahal jumped to the conclusion that such capacity was now fair game and should be reflected in calculating PP&L's reserve margins.

The Company strenuously disagrees with Mr. Kahal's interpretation and application of Section 1323(c). First, Mr. Kahal's position cannot be reconciled with Section 523 of the Code (66 Pa.C.S. § 523), which was added at precisely the same time as Section 1323(c).[9/] Section 523 is entitled Performance factor consideration and expressly directs the Commission, in its ratesetting function, to take into account, amongst other things:

> (4) Action or failure to act to encourage development of cost-effective energy supply alternatives such as conservation or load management, cogeneration or small power production for electric and gas utilities.

Through Section 523, the Legislature created ratemaking incentives designed to reward utilities for their efforts to promote cost-effective cogeneration or small power production projects. It would obviously make a mockery of that provision to turn around and penalize PP&L for its efforts in that regard by

[9/] Both provisions became effective on July 10, 1986 with the enactment of P.L. 1238, No. 114.

utilizing QF output to justify an excess capacity adjustment. Notably, Mr. Kahal was unaware of the existence of Section 523 (Tr. 1608).

A far more reasonable and legally defensible interpretation of Section 1323(c) was offered by Dr. Hieronymus, who suggested that the appropriate focus of the inquiry should be on whether the utility could have foreseen its exposure under PURPA at the time it undertook the capacity expansion in question. As Dr. Hieronymus explained (PP&L St. 16-R, p. 32):

> The logic of the legislature's position is that the utility should not be penalized for its own capacity construction by virtue of purchasing QF output. The eight-year window allowed would, under most circumstances, protect the utility from an inappropriate excess capacity disallowance resulting from its compliance with PURPA. I interpret the time-limited nature of the protection as meaning that the Commission is entitled to use QF capacity to disallow costs when the utility blatantly disregards likely QF capacity and over-builds its system. By 1986, it had become clear that cogeneration that could be "put" to the utility was quantitatively significant and an important fact for utilities to take into account in capacity planning. PP&L clearly has not disregarded likely amounts of QF capacity in its post-1986 capacity planning. Indeed, other than the highly cost effective Susquehanna uprate, it has added nothing to owned or leased capacity since that time. Hence, the logic of the legislation, when applied to PP&L's circumstances, dictates that the QF capacity should be ignored for purposes of a "used and useful" determination.

Significantly, Dr. Hieronymus' application of Section 1323(c) is fully consistent with the Commission's own view of the Legislature's intent. In 1987, the Commission issued a proposed

Statement of Policy on the Treatment of Purchases of Capacity from Qualifying Facilities in Excess Capacity Determinations (the "Policy Statement"). The Policy Statement, which was published for comment in the Pennsylvania Bulletin on July 18, 1987 (Vol. 17, No. 29, pp. 3035-3038), provided that, in cases where Section 1323(c) did not control (i.e., where, as here, the eight-year window had closed), the Commission would not consider QF output in addressing excess capacity issues other than in those instances where a utility imprudently failed to cancel or defer the construction of a new generating unit, the need for which had been displaced. In support of its position, the Commission reasoned as follows:

> If a utility is unwilling to negotiate with a developer, legal recourse is available to the developer by the filing of a formal complaint with the Commission. However, the time and expense that such a formal proceeding necessarily entails is most often sufficient to discourage a developer from pursuing its remedy. Therefore, it is important that some assurance be provided to utilities that their voluntary entrance into an agreement with the developer of a QF will not place the utility's investment in its own generating units unreasonably at risk. An excess capacity adjustment made, in part, on the basis of the availability of QF capacity would place a utility's investment at risk, and would be likely to discourage continued development of qualifying facilities.
>
> On the other hand, it would not appear reasonable to wholly insulate a utility from any consideration of capacity provided by QFs. Public utilities are under a continuing duty to supply adequate service at the lowest reasonable cost and therefore are obliged to cancel or defer the construction of additional capacity where firm, reliable capacity becomes available from QFs at a

> cost equal or lower than that which the utility otherwise would incur.
>
> *   *   *
>
> We conclude from the foregoing discussion that a policy of excluding consideration of executed purchase power agreements with qualifying facilities from the reasonable reserve margin and economic benefits tests of Section 1323 may be warranted in most cases. The exception to this general policy would be situations where purchases of firm and reliable capacity, under long term contract, have offset the need for a utility's own generating unit, and where the utility nevertheless failed to defer or cancel the construction of its own generating unit when cancellation or deferral would have represented the most economical choice for the utility's ratepayers.

Although the Policy Statement was never finalized, the Commission has ruled to the same effect in a number of proceedings involving requests by utilities that it (1) pre-approve the rate recovery of payments to be made to QFs and (2) declare that the addition of QF capacity pursuant to such agreements will not be considered in future excess capacity determinations. For example, in Petition of West Penn Power Co., 1987 Pa. PUC LEXIS 153 (1987), industrial intervenors contended that the Commission lacked the authority to exclude QF output from excess capacity analyses where Section 1323(c) did not apply. In rejecting this assertion, the Commission held:

> Contrary to arguments by Armco, Inc. and Allegheny Ludlum Corporation, the General Assembly has not mandated the inclusion of PURPA 210 generating capacity in those cases where the capacity is not expressly to be excluded. In fact, legislation at 66 Pa.C.S. § 523(b)(4) specifically directs that the Commission encourage the development of

> cogeneration and small power production, and that utilities failing to cooperate be subject to ratemaking penalty.

The Commission, citing its proposed Policy Statement, therefore granted the relief sought by West Penn.

On appeal, the OCA argued that the Commission's declaration violated the due process rights of West Penn's customers because they had not been provided adequate notice of the proceeding. While the Commonwealth Court agreed that the Commission's reliance on the Policy Statement was in error because it had not been finalized, the Court also made it clear that the Commission had the authority to reach the conclusions it had regarding the proper treatment of QF output:

> [B]ecause the commission has not adopted the Policy Statement, the commission's order in this case is the administrative action that affects the ratepayers' rights regarding the excess capacity treatment of the Milesburg project capacity, and hence is adjudicatory in nature. This conclusion does not mean that the commission does not have the power to decide to disregard the Milesburg project capacity in excess capacity determinations involving West Penn's existing capacity, but rather that the commission may not make such a decision without first providing the ratepayers with notice and a hearing.

Barasch v. Pa. P.U.C., 119 Pa. Cmwlth. 81, 109-110, 546 A.2d 1296, 1309 (1988); see also Re West Penn Power Co., 71 Pa. P.U.C. 60, 78 (1989); Pennsylvania Electric Co. v. Pa. P.U.C., 166 Pa. Cmwlth. 413, 426, 648 A.2d 63 (1994) ("[I]f QF capacity is excess, the ratepayers, not the utility or the QF, are required to assume the burden of paying for capacity not needed leading to increased rates.").

In view of the foregoing, the ALJ should conclude, as a matter of sound regulatory policy and simple equity, that QF output may not be included in the determination of PP&L's reserve margins. And, based on that finding, the excess capacity adjustments proposed by the OTS and the OCA should be rejected.

(2) Factors That Should Be Considered In Evaluating The Reasonableness Of PP&L's Reserve Margins

As indicated previously, widely divergent views have been expressed as to what constitutes a "reasonable" reserve margin for PP&L and those differences will be explored in due course. At this stage, however, it is significant to note that all of the witnesses who addressed the issue in this proceeding agreed, in theory if not necessarily in practice, that the determination of an appropriate reserve margin must be based on an evaluation of the specific characteristics of the utility system in question, and not simply in accordance with certain arbitrary "rules of thumb". Or, as the Commission stated in Pa. P.U.C. v. Pennsylvania Power Co., Docket No. R-832409 (April 11, 1984) (Order, p. 12):

> We do not believe, however, that a capacity reserve margin of 20% or any other specific percentage could or should apply as an industry standard. An acceptable reserve generating capacity margin for any particular electric utility is dependent upon the generation mix,

> availability of generating units, peak load requirements, the period during which the peaking capacity is required, rates of forced outages, transmission capabilities, interconnections with other utilities and transfers of energy during emergency. These are some of the operating factors which must be considered when reaching a determination concerning an acceptable generating reserve margin.

See also Pa. P.U.C. v. West Penn Power Co., Docket No. R-842632 (August 28, 1985) (Order, p. 43) ("[T]here is no magic number which applies to all utilities at all times.").

That a system-specific analysis is required should be obvious. What makes a particular reserve margin "reasonable" and another "unreasonable" is the extent to which it enables a utility to satisfy its customers' load requirements consistent with the attainment of other corporate objectives. And, because those requirements and objectives, as well as the capacity resources available to meet them, can and do vary significantly from time to time, the magnitude of a reserve margin alone may tell less than half the story. Stated differently, the "reasonableness" of an individual utility system's reserve margin must reflect consideration of a whole host of factors. For this reason, and as Mr. Sipics explained (PP&L St. 9, pp. 7-8), PP&L firmly believes that a "reasonable" reserve margin must be viewed in terms of a range of values:

> It is not correct to think of an appropriate reserve margin as a single figure. Given the factors and contingencies that must be balanced in assessing reserve margins, such a degree of precision is not possible and should not be attempted. Rather, an appropriate reserve margin

> exists within a range that is defined on the basis of accepted measures of reliability; the practicalities of adding generating resources (i.e., in units of sufficient size to capture reasonable economies of scale); load shape and duration; the need for fuel diversity; the level of control the utility has over its planned resources; and the inherent limitations of available forecasting techniques.

With regard to the low end of the range, there is no dispute. As a member of the PJM, the Company must have in place a certain level of reserves, denominated as its "installed capacity obligation", which is designed to enable it and the PJM to maintain adequate system reliability. For PP&L, that level of reserves, when expressed in terms of its winter peak, presently equals 12% (PP&L. St. 9, p. 10).

The PJM's required reserves, as well as the installed capacity obligations assigned to its member companies, are determined through an extraordinarily complex analysis which attempts to determine the resources needed to satisfy the so-called one-day-in-ten-years loss of load probability ("LOLP") reliability standard. As its name would imply, this standard, when properly applied, defines that level of reserves which, at least theoretically, assures that, on an average or probabilistic basis, demands will exceed available resources on no more than one occasion over a ten-year period (PP&L St. 9, p. 9).[10]

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[10] Neither OTS witness Metro nor OCA witness Kahal took issue with the one-day-in-ten-years LOLP standard (Tr. 1510; Tr. 2364).

LOLP analyses are, of course, subject to any number of vagaries and uncertainties. In addition, and as discussed infra, there are various factors not considered in the PJM's calculations which can and do substantially affect system reliability. The clearest evidence of this may be found in the fact that, despite all of its sophisticated computer modelling, the PJM has experienced eight loss of load occurrences in the past eight years, the most severe coming in January 1994 when rotating blackouts had to be implemented (PP&L St. 9-R, pp. 5-6).

This is not to suggest, as Mr. Kahal implied (OCA St. 2A, p. 13), that PP&L is "second guessing" the PJM's procedures for evaluating the region's reliability needs. Nor, for that matter, is PP&L accusing the PJM of performing its functions improperly or ineffectively. Rather, the point to be made, as Mr. Sipics candidly explained, is that "reliability calculations aren't perfect" (Tr. 271).[11] Moreover, even if foresight were 20-20, it would be impossible, from an operating standpoint, to precisely match loads and resources year-by-year. These factors must, therefore, be taken into account in determining what constitutes the upper end of a "reasonable" reserve margin range for PP&L or any other electric utility.

Planning Uncertainties. Despite the best efforts of PP&L and PJM system planners, each of the three components that

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[11] If fact, as Mr. Sipics pointed out (Tr. 2386), the PJM is currently reviewing its reliability program.

ultimately define the Company's required reserves -- load level, available resources and the PJM installed capacity obligation -- is highly uncertain. For example, Dr. Slivka's load forecast, which was accepted and utilized by all parties, assumes that peak demands will grow, on average, by approximately 130 Mw per year over the next decade. As Dr. Hieronymus pointed out, however, load growth can be and has been far less predictable. In fact, in the early 1990's PP&L's winter peak increased by 313 Mw and 273 Mw in successive years (PP&L St. 16-R, p. 21).

Capacity resources can also change over time in unanticipated ways. Thus, in this case PP&L has reflected, as an available resource, 345 Mw of interruptible load. Yet, as acknowledged by OTS witness Metro (Tr. 1517), the Company has no control over whether an interruptible service customer actually sheds load when asked to do so. Furthermore, because interruptible service contracts are renewable annually, some or all of this resource could be lost if interruptible service customers move off the rate or reduce their interruptible loads. In light of the Company's proposal to make its interruptible service offerings more cost-based, and with interruptions likely to become more frequent, this is more than just a theoretical possibility (PP&L St. 16-R, pp. 21-22).[12/]

[12/] As discussed supra, there is similarly no guarantee that QFs will continue to perform as they have in the past (PP&L St. 9, pp. 10-11).

Finally, it is important to note that the Company's installed capacity obligation to the PJM must be satisfied both on a planning basis and on an "after-the-fact" accounting basis. Mr. Sipics described the process as follows (PP&L St. 9-R, p. 5):

> PP&L's minimum 12% PJM reserve requirement is set two years in advance of the planning period. Following the completion of the PJM planning period, "after-the-fact" accounting adjustments are made to PP&L's obligation to reflect actual unit performance and loads. In addition, available capacity is reduced for peak period maintenance. All of these adjustments must be considered in developing an accurate characterization of PP&L's total capacity obligation. Within the last two years, these adjustments have increased PP&L's reserve level required for PJM installed capacity accounting purposes by as much as 5.3 percentage points (351 MW) above its planned obligation.

These planning uncertainties make it incumbent upon PP&L to maintain reserves substantially in excess of its designated PJM minimum requirement.

<u>Generating Unit Availability During Winter Months</u>. PP&L and its customers derive substantial benefits by virtue of the Company being a winter-peaking utility in a summer-peaking power pool. Indeed, this diversity explains why the Company's installed capacity obligation is so much lower than the PJM's minimum reserve requirement, which was set at 22% (PP&L St. 9, pp. 10-11). At the same time, however, PP&L faces meaningful exposure to relatively high unit unavailability during winter months.

In the PJM's reliability calculations, generating unit availability and load are assumed to be independent variables. Yet, as noted by Mr. Sipics (PP&L St. 9-R, p. 5; Tr. 2383-2384), they are not. To the contrary, the same factor -- cold weather -- not only leads to increased customer demands (i.e., home heating), but also enhances the prospect that units will be unable to run due to frozen coal piles, disruptions in the delivery of oil and the interruption of fuel supplies to gas-fired plants. Significantly, this problem was highlighted by Commissioner Hanger in a recently published article evaluating the causes of the January 1994 rotating blackouts. See Public Utilities Fortnightly, May 1, 1995, pp. 27-30.

"Lumpiness". Any assessment of the reasonableness of PP&L's reserve margins must also recognize that large base load capacity additions, such as those constructed by the Company in the 1980s, are inherently "lumpy" and will inevitably lead to a period of temporary capacity surplus.

The Commission has recognized this practical planning consideration on a number of occasions. In the Unit 2 Case (pp. 18-19), the Commission, quoting favorably from the Recommended Decision of Administrative Law Judge Klovekorn in a prior PP&L case, stated:

> 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.

In two subsequent proceedings, the Commission expressly declined to adopt proposed excess capacity adjustments notwithstanding findings that the utilities' reserve margins would exceed the optimum range used for planning purposes. Thus, in Pa. P.U.C. v. Philadelphia Electric Co., Docket No. R-850152 (June 27, 1986) (Order, pp. 36-37), the Commission affirmed Administrative Law Judge Matuschak's determination that a "reasonable increase in reserve capacity must be allowed before excess capacity comes into play". And, in Pa. P.U.C. v. West Penn Power Co., Docket No. R-850220 (July 24, 1986) (Order, p. 47), where the disparity between actual and optimum reserve margins approximated 11.0%, the Commission reached the same conclusion, reasoning as follows:

> In contrast to the planned, operational reserve margin criteria just discussed is the currently projected, actual reserve margin which results from the vagaries of imperfectly predictable load growth, long lead-time construction programs, and other factors. It is this kind of margin which is, for example, subject to large quantum changes when a large unit is added or withdrawn.

OCA witness Kahal tried to downplay the "lumpiness" factor by noting that utilities no longer plan for large generating units but instead add capacity in relatively small increments. In addition, Mr. Kahal contended that lumpiness "has little to do with PP&L's circumstances" because SSES 2 entered service ten years ago. On this basis, he concluded that PP&L's alleged excess was not, therefore, "attributable to the temporary imbalance associated with absorbing a recently installed large capacity increment" (OCA St. 2, p. 14).

Mr. Kahal's first point is factually correct but logically irrelevant. That PP&L <u>today</u> could install a new 200 Mw combustion turbine or combined-cycle unit begs the issue. As Dr. Hieronymus observed (PP&L St. 16-R, p. 26):

> This case is not considering whether a new 200MW gas unit creates excess capacity. It is about whether SSES 2 creates excess capacity, and SSES 2 is not a small gas unit. Indeed, the small gas technology now in vogue was not available when SSES 2 was planned or completed.
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> Mr. Kahal accepts that in earlier times -- the period when SSES 2 was planned and built -- large units were the commonplace capacity additions. The logic of his position is that a reasonable range at that time would have spanned the lumpiness caused by large units. His use of a smaller range today suggests a "reasonable range" that varies with time and with technology. If this is the case, then the "reasonable range" in a rate case considering a large unit that was prudently built should be chosen with reference to the lumpiness inherent in such units.

Perhaps more importantly, it is abundantly clear that the "excess" which Mr. Kahal finds objectionable in not "attributable" to SSES 2. As the record in this case confirms, and as Mr. Kahal essentially admitted (Tr. 2367-2368), the "lump" created by SSES 2 would have been fully absorbed by now but for the unavoidable purchase by PP&L in later years of QF output. Consequently, if QF output is to be recognized as an available capacity resource, which PP&L believes would be inappropriate for all the reasons previously stated, then "lumpiness" remains a valid consideration in establishing the upper end of PP&L's allowable reserve margin.

The discussion to this point has focused on factors -- planning uncertainties, unit availability during winter months and "lumpiness" -- which speak to the issue of system reliability. However, as Mr. Sipics stressed in his rebuttal testimony (PP&L St. 9-R, pp. 6-8), not all capacity is added for reliability purposes. The most obvious example of this is the QF output which PP&L purchased pursuant to Federal mandate. But, there are others.

Approximately 90 Mw of PP&L's alleged "excess" may be traced to capacity uprates at SSES 1 and 2. These uprates provide energy at about 1.5¢ per kilowatthour ("kWh"), or considerably below the Company's avoided cost of energy of 2.8¢ per kWh. Another 345 Mw of capacity resources is due to PP&L's implementation during the 1991/1992 planning period of interruptible service options designed to encourage economic development in central-eastern Pennsylvania. As Mr. Sipics explained (PP&L St. 9-R, pp. 10-11), the Commission should carefully weigh the reasons why this capacity came to be in evaluating the reasonableness of PP&L's reserve margins:

> If a resource is added solely to obtain low cost energy, its capacity value should not be used to penalize the Company by displacing pre-existing

generation in an "excess capacity" analysis. For example, as I previously explained, the capacity uprating of Susquehanna Units 1 and 2 provides extremely low-cost energy. It makes economic sense to pursue that source of low-cost energy irrespective of PP&L's existing installed capacity situation. Also, if a resource is added because PP&L is required by law to purchase its output, as is the case with QFs, or because the resource was a consequence of PP&L's efforts to pursue economic development initiatives, as was the case with IL, then the capacity value of such resources likewise should not be used to penalize the Company by displacing pre-existing generation in an "excess capacity" analysis.

Obviously, in each instance, the timing of the capacity resource addition is significant, which is why I emphasize that the three resources I have identified above should not displace "pre-existing" generation. However, the Susquehanna uprating, NUG and IL could properly be included in assessing whether a subsequent capacity addition is needed for reliability reasons or is "excess" for ratemaking purposes.

In summary, a reserve margin well in excess of 12% can be justified on reliability grounds alone by simply recognizing planning uncertainties (e.g., the 5.3% "after-the-fact" accounting adjustment made in 1994) and "lumpiness" (i.e., even Messrs. Kahal and Metro would allow a 3%-4% "lump"). Moreover, consideration must be given to the fact that 435 Mw of the Company's available resources, or roughly 6.5% of its peak demands, are attributable to cost-effective measures (i.e. capacity uprates and interruptible service options) undertaken not for reliability purposes, but rather for the overall benefit of PP&L's customers. Based on the foregoing, PP&L submits that its proposed reserve margin range of 12%-20% for reliability purposes is entirely reasonable.

Finally, even if all of the above were to be ignored and the situation evaluated purely on a "macro" level, one would find that the Company's indicated reserve margins fall well below the level which the Commission has found acceptable for PP&L and for other Pennsylvania electric utilities. Although the Company does not endorse such an approach for the reasons discussed, it is worth noting that PP&L's projected reserve margins are considerably below the 22% figure approved in the Unit 2 Case.[13/] Furthermore, the upper end of the Company's proposed reserve margin range is less than that previously allowed Duquesne Light Company (18%-22%), Pennsylvania Power Company (20%-28%), Philadelphia Electric Company (22%), and West Penn Power Company (28%-39%).[14/] It is, therefore, readily apparent that PP&L's present and prospective reserve margins are reasonable whether measured in terms of system-specific or more generic criteria.

(3) Deficiencies In The Opposing Parties' Reserve Margin Proposals

The reserve margins recommended by the OTS (16%) and the OCA (15%) are not based on any meaningful evaluation of PP&L's loads and resources, but rather represent the subjective judgement of

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13/ In fact, the Company's reserve margin during the first rate effective year is expected to fall below 22.0% even if QF output is counted as an available capacity resource (PP&L Ex. JFS-1).

14/ See Pa. P.U.C. v. Duquesne Light Co., 66 Pa. P.U.C. 518 (1988); Pa. P.U.C. v. Pennsylvania Power Co., 93 PUR4th 189 (1988); Pa. P.U.C. v. Philadelphia Electric Co., Docket No. R-891364 (May 16, 1990); Pa. P.U.C. v. West Penn Power Co., 61 Pa. P.U.C. 711 (1986).

their respective witnesses. OTS witness Metro, for example, characterized his 4% increment over PP&L's 12% installed capacity obligation as a "contingency" or "padding" factor (OTS St. SR5, p. 2). OCA witness Kahal, in turn, sought to defend his even more modest 3% increment as a "generous cushion" (OCA St. 2, p. 16).

The principal deficiency in Mr. Metro's presentation, as well as Mr. Kahal's, is the failure to consider any of the system-specific reliability factors enumerated by Mr. Sipics and discussed in the preceding Section of this Initial Brief. Mr. Metro effectively ignored them in both his direct and surrebuttal testimony.[15] Mr. Kahal similarly paid little more than lip-service to such factors, clinging to the view that they somehow had already been taken into account by PP&L and the PJM in establishing the Company's 12% installed capacity obligation (OCA St. 2A, p. 9). Mr. Sipics, who, during his twenty-five year career with PP&L, has been extensively involved in a variety of PJM activities, explained that Mr. Kahal was simply mistaken (Tr. 2381-2384).[16]

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[15] The only adjustment made by Mr. Metro to the Company's minimum PJM reserve requirement was initially identified by him as a "forced outage factor" (OTS St. 5, p. 20). However, after certain errors were pointed out by Dr. Hieronymus (PP&L St. 16-R, pp. 27-28), Mr. Metro explained that his calculations were not intended to reflect the forced outages that could occur at the time of PP&L's system peak but rather, as noted above, a "contingency" factor.

[16] Mr. Sipics has served on the PJM's Operating Committee, its System Reliability Task Force and is presently a member of the PJM's Management Committee, In addition, he performed a

Messrs. Metro and Kahal also chose to disregard or substantially discount the other, non-reliability related factors cited by Mr. Sipics in support of the Company's proposed reserve margin range. Again, Mr. Metro's testimony is silent on this point. Mr. Kahal, on the other hand, did not question PP&L's decisions to uprate SSES or to implement economic development rates, but instead complained that it would be difficult for the Commission to review the reasonableness and cost-effectiveness of such capacity additions in applying a physical excess capacity test (OCA St. 2A, p. 16). PP&L disagrees and would merely note that the Commission is already required to perform such evaluations in a number of different contexts. See, e.g., 66 Pa. C.S. §§ 514, 517-521; Tr. 2365-2367. More importantly, and as Dr. Hieronymus observed (PP&L St. 16-R, pp. 37-38), the failure to consider such undertakings in an excess capacity analysis would create inappropriate, and presumably unintended, disincentives:

> Q. Do you have any other comments that you wish to make concerning the approach used by the OTS and OCA witnesses in assessing the need for PP&L's capacity?
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> A. Yes. I simply would like to note that adherence to simple calculations of after-the-fact reserve margins for determining whether PP&L is entitled to be paid for its owned and leased capacity could create adverse incentives. If a utility had believed over the past decade that it was going to lose a great deal of money for every megawatt of "capacity" that it created, it would have had a

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series of reliability analyses for the PJM's Planning and Engineering Committee in the mid-1970s (Tr. 2385).

powerful incentive to minimize the amount of additional capacity on its system regardless of other economic or policy considerations. Decisions regarding QF contracts, load management and unit uprates would have been scrutinized from that perspective. In fact, the utility likely would have sought methods of reducing capacity reserves including plant retirements and load growth.

The OTS and OCA witnesses claim disinterest in why reserves are what they are, and look only to whether the achieved reserve margin fits into a narrow range above the PJM minimum. I do not believe that this is or should be viewed as an appropriate public policy for Pennsylvania.[17]

Finally, and wholly apart from its other flaws, Mr. Metro's recommended 564 Mw adjustment does not, in any way, reflect the excess capacity that he himself claims PP&L will have in the short-term. To the contrary, Mr. Metro's exhibit (OTS Ex. 5, Sch. 1) shows only 371 Mw of alleged excess capacity for the first year that new rates will be effective. Instead, the 564 Mw figure represents an average value computed over a nine-year "defined planning period" (Tr. 1512). PP&L objects in the strongest possible terms to the notion, implicit in Mr. Metro's analysis, that it may be penalized today for capacity that he speculates may be "excess" years from now.[18]

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[17] That Mr. Kahal would ignore PP&L's interruptible load is particularly troublesome given his prior acknowledgement that there is "a possible degradation to reliability from increased reliance on load management" (PP&L St. 16-R, p. 36) (quoting from Mr. Kahal's report in a 1993 Delmarva Power and Light Company proceeding).

[18] The Company further notes that Mr. Metro's calculations specifically assume that PP&L's request to recover returning JCP&L fixed costs through the ECR is approved. As Mr. Metro acknowledged (Tr. 1523), there would be no excess capacity

c. Even Though The Economics Of SSES 2 Need Not Be Addressed, The Record Confirms That Unit 2 Produces Annual Benefits When Compared To The Cost Of A Logical Baseload Alternative

OTS witness Metro properly recognized that "economic" excess capacity was not, or at least should not be, an issue in this proceeding because PP&L was not seeking to recover the costs of any new generating units (OTS St. 5, pp. 15-16). Unfortunately, Mr. Kahal reached a very different conclusion, taking the position that (1) Section 1323(a) of the Code (66 Pa.C.S. § 1323(a)) applied and (2)the economics of SSES 2 should be measured against the hypothetical market price of power in a deregulated environment. Indeed, because Mr. Kahal's "physical" excess capacity analysis confirmed that a significant portion of SSES 2 was used and useful even by his standards, it was only on the basis of his "economic" excess capacity analysis that he could recommend the denial of an equity return on PP&L's entire Unit 2 investment.

Mr. Kahal's understanding of the purpose and reach of Section 1323(a) is misguided. Moreover, the economic test which he seeks to apply is unprecedented, unsupported and inappropriate. For these and the other reasons set forth below, his "economic" excess capacity analysis should be disregarded and his proposed adjustment, which would reduce PP&L's rate request by approximately $62.0 million, should be rejected.

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adjustment under his approach if that request were denied.

(1) <u>Inapplicability Of Section 1323(a)</u>

As noted at the outset, the Commission, in the <u>Unit 2 Case</u>, stated unequivocally that PP&L could seek modification of the excess capacity adjustment therein adopted upon showing that <u>either</u> (1) SSES 2 was needed for reliability purposes <u>or</u> (2) its net economic benefits had begun to outweigh its net costs. In this proceeding, the Company has demonstrated conclusively that SSES 2 no longer represents "physical" excess capacity. In fact, and as pointed out by Dr. Hieronymus, without SSES 2 PP&L would not have sufficient capacity during the future test year to meet its installed capacity obligation to the PJM (PP&L St. 16-R, p. 23). Accordingly, the ALJ need not even address the issue of "economic" excess capacity.

Mr. Kahal's belief, again apparently based on "advice of counsel", that the subsequent enactment of Section 1323(a) somehow modified and/or revoked the Commission's decision in the <u>Unit 2 Case</u> is clearly erroneous. The heading of Section 1323 refers specifically to <u>Procedures for new electric generating capacity</u>. The applicability of Section 1323(a), in turn, is expressly limited by the following introductory language: "Whenever a public utility <u>claims</u> the costs of an electric generating unit in its rates <u>for</u> <u>the</u> <u>first</u> <u>time</u> . . ." (emphasis added).

SSES 2 does not represent "new" generating capacity. In fact, Mr. Kahal went to great pains to point that out in explaining why, in his view, "lumpiness" was not a valid consideration in evaluating the reasonableness of PP&L's reserve margin today (OCA St. 2A, p. 17). It is equally clear that the Company is not now seeking recovery of the costs of SSES 2 "for the first time". Rather, that claim was made in the Unit 2 Case and, to a large extent, the costs of SSES 2 are already reflected in current rate levels.

Finally, Mr. Kahal's position regarding the reach of Section 1323(a) cannot be reconciled with his interpretation and application of Section 1323(c), both of which were added to the Code as part of the same overall regulatory scheme. On the one hand, Mr. Kahal contends that the eight-year window provided by Section 1323(c) has closed and that the availability of QF output may therefore be taken into account in the Commission's "physical" excess capacity analysis. On the other hand, he argues that SSES 2 should be treated as if it were just entering service and being claimed in rates for the first time. Mr. Kahal simply cannot have it both ways.

The Company submits that the clear language of Section 1323(a) negates any argument that it applies in this case. Consequently, there can be no "rebuttable presumption" that PP&L has excess capacity. And, having shown that SSES 2 is needed for reliability purposes, the Company should be allowed a full return on its investment in that facility.

(2) Mr. Kahal's Flawed "Economic Benefits" Test

Regardless of whether Section 1323(a) is found to apply, Mr. Kahal's proposed "economic benefits" test must be rejected. In effect, Mr. Kahal is saying that a generating unit that was planned in the 1970s and completed in the mid-1980s, should, in 1995, be measured against the hypothetical cost of "deregulated" power in the early 2000s. Needless to say, this approach is unprecedented in Pennsylvania and, to the best of the Company's knowledge, has not been adopted in any other jurisdiction either.[19/] And, for good reason.

The flaws in Mr. Kahal's market-based test are numerous and profound. The first problem is that it assumes a set of conditions which is at odds with his analysis of PP&L's reliability requirements. As Mr. Sipics explained (PP&L St. 9-R, pp. 17-18):

> Mr. Kahal does not apply a consistent view of future market conditions in his analysis of PP&L's capacity position. On one hand, Mr. Kahal argues that the hypothetical [market clearing price of generation] that might exist in a fully competitive market is the appropriate test for determining economic excess capacity. On the other hand, Mr. Kahal argues that the assessment of whether physical excess capacity exists should not consider changes likely to occur in a more competitive market, but instead should be based solely on PP&L's current Installed Capacity

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19/ Mr. Kahal similarly indicated that he was not aware of any regulatory commission which had applied his approach to deny a return on an existing generating unit (Tr. 1624).

> Obligation. These arguments are clearly inconsistent and yield unsupportable results.

Dr. Hieronymus testified to the same effect: "[I]t is wholly inappropriate to use the market prices for a deregulated power market to determine the appropriate ratemaking treatment for a single generating unit in determining regulated revenue requirements" (PP&L St. 16-R, p. 43).

Of equal concern is Mr. Kahal's selective application of his market-based test. If and/or when the generation function is deregulated, all of PP&L's generation, and not simply SSES 2, will be subject to market forces. In such a deregulated environment, however, certain production facilities will be economic "winners" (relative to the then-existing cost of service) and others economic "losers". Mr. Kahal would inappropriately isolate PP&L's newest generating unit for market treatment without considering whether other facilities may presently be undervalued (PP&L St. 9-R, p. 18; PP&L St. 16-R, p. 44).

The same, of course, could be said of PP&L's other assets. As noted by Dr. Hieronymus (PP&L St. 16-R, p. 48), the use of a fair value test with respect to the Company's transmission and distribution facilities would indicate a market value that is more than $1.3 billion above historical costs. The symmetrical application of Mr. Kahal's methodology would therefore require a sizeable upward adjustment to PP&L's current rate request to reflect those assets with market values above costs. Indeed, the failure to do so would result in precisely the type of mixing of rate methodologies which the U.S. Supreme Court suggested would be constitutionally repugnant in Duquesne Light Co. v. Barasch, 488 U.S. 299, 315, 109 S.Ct. 609, 619 (1989) ("[A] State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions.").

In his surrebuttal testimony, Mr. Kahal responded to the foregoing criticisms by noting that (1) he had not proposed that any PP&L asset be priced at market value and (2) transmission and distribution were monopoly functions (OCA St. 2A, pp. 31-32). Mr. Kahal's observations clearly miss the mark and should not be allowed to camouflage the conceptual deficiencies in this analysis.

With respect to Mr. Kahal' first point, the fact that he could have recommended an even more draconian excess capacity adjustment is irrelevant. Rather, what is significant is that he resorted to a deregulated market-based model to justify the disallowance of regulated costs. It matters not that he stopped short of utilizing market price data to actually quantify his adjustment. Mr. Kahal's second point is equally unconvincing. Although some might contend that generation is no longer a pure monopoly function, it is still regulated as if it were and, therefore, should continue to receive the same ratemaking treatment accorded other utility assets.

Mr. Kahal's economic benefits test should also be rejected because it calls upon the Commission to truncate the ongoing debate over the recovery of "stranded costs". In his direct testimony (OCA St. 2, p. 6), Mr. Kahal stated succinctly that his proposed excess capacity adjustment "effects roughly a 50/50 sharing between ratepayers and shareholders of the surplus of cost over market". Yet, as explained by Dr. Hieronymus (Tr. 2388-2389), the "surplus of cost over market" is the very definition of stranded cost. This issue is far too complex and important to attempt to resolve in this proceeding.[20]

In addition to these shortcomings, Mr. Kahal's "economic benefits" test, coupled with his view that the "fact" of excess capacity is determinative, cannot be reconciled with the "rebuttable presumption" feature of Section 1323(a). In Pa. P.U.C. v. West Penn Power Co., 63 Pa. P.U.C. 295, 302-03 (1987), the Commission, in reviewing this language, reasoned that the Legislature "must have intended to accord the utility some meaningful opportunity to again come forward to meet its burden". However, it is extremely doubtful that many large base load plant constructed in the past twenty years could beat the market prices

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[20] Furthermore, given the uncertainties regarding future competitive markets, there can be no justification for saddling PP&L with stranded costs now (PP&L St. 16-R, p. 44).

assumed by Mr. Kahal in his analysis. In fact, Mr. Sipics suggested that the application of Mr. Kahal's approach would likely result in the rate base exclusion of "a substantial portion of all generation assets nation-wide" (PP&L St. 9-R, pp. 15-16).[21]

Even if there were conceptual support for Mr. Kahal's approach, his market price assumptions, which were derived, in part, from a PP&L study entitled Market Clearing Price of Generation ("MCPG"), must be accepted for what they are. As Mr. Sipics explained (PP&L St. 9-R, pp. 16-17):

> The MCPG Study offers only one hypothetical view of the future. The analysis provided a very preliminary estimate of the market price of generation in a <u>fully competitive</u> electricity market (i.e., with both wholesale and retail wheeling). The analysis assumes one scenario of the future of the electric utility industry. Many other scenarios are also plausible. In addition, the MCPG Study employed generally conservative assumptions and methods, which most likely understate the competitive market prices of electricity. The information in the MCPG Study was designed for broad strategy discussions and to set aggressive targets for PP&L to attempt to attain. The study cannot be considered a definitive or complete analysis of the factors that determine economic value.

Notwithstanding Mr. Kahal's assertions to the contrary (OCA St. 2A, p. 6), PP&L made no attempt to "distance" itself

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[21] Further evidence that Mr. Kahal's test does not comport with the Legislature's intent may be found in his concession that "the concept of a wholly competitive generation market really wasn't very well developed" during the 1980s (Tr. 1622). It was during that period, of course, when Section 1323(a) was enacted.

from the MCPG Study, but instead endeavored to put it in proper prospective. To that end, it was necessary and appropriate for Mr. Sipics and Dr. Hieronymus to identify and comment upon some of the limitations of the Study itself: (1) "uneconomic" units, which, in all likelihood, would be shut down, were assumed to continue to operate; (2) QFs were treated as "must-run" units; and (3) conservative assumptions were made with respect to the cost of environmental compliance at fossil-fired units (PP&L St. 9-R, p. 17; PP&L St. 16-R, p. 51). Each of these assumptions, while perhaps acceptable for the purpose for which the Study was performed, served to understate the future market price of electricity.

In the final analysis, Mr. Kahal's "economic benefits" test creates a moving target which, depending upon input assumptions, changes in fuel prices and technological advances, can produce widely disparate results from year to year. Only three years ago, Mr. Kahal determined that Pennsylvania Electric Company's avoided cost approximated 8.5¢ per kWh on a levelized basis over a thirty year horizon (Tr. 2375-2377). As can be seen from PP&L Cross-Examination Exhibit 1, Mr. Kahal, in that case, developed a first year (1997) avoided cost figure of 5.75¢ per kWh, which then escalated to over 8.0¢ per kWh by the year 2006.

What is significant about Mr. Kahal's presentation in the Pennelec case is that his avoided cost calculations produced figures higher than those projected for SSES 2. In fact, this is true whether or not the aggressive goals identified in PP&L's Strategy 2000 report are actually achieved. In other words, if PP&L had filed a base rate case three years ago, SSES 2 presumably would have been found "economic" under Mr. Kahal's market-based test. This further underscores the arbitrary and time-sensitive nature of his approach.

For all of the reasons set forth above, Mr. Kahal's severely flawed "economic benefits" test should be rejected.

(3) Dr. Hieronymus' Alternative Plant Analysis

Rather than rely on highly uncertain estimates of future market-based prices, Dr. Hieronymus evaluated the economics of SSES 2 in light of the conditions PP&L would have faced in a world in which SSES 2 did not exist. Confronting a projected capacity shortfall in the mid-1990s, the Company would not have simply waited to see what capacity might be available and at what price. Indeed, its statutory obligation to service would have precluded such complacency. Rather, the Company would have had no choice but to proceed with a logical baseload alternative.

As noted by Dr. Hieronymus (PP&L St. 16-R, p. 53), coal generation was the most economic technology for providing baseload capacity in the mid-1980s. The only other possible option would have been for PP&L to install combined-cycle gas turbine units. However, such units were viewed, at the time, as a much less attractive alternative because of expected performance and the historic and anticipated volatility of gas prices. Consequently, for purposes of his analysis, Dr. Hieronymus assumed that the Company would have embarked on the construction of a new coal plant, consisting of two units with a combined capacity of 990 Mw. Dr. Hieronymus described the process in these terms (PP&L St. 16-R, p. 55):

> In brief, I structured the analysis to measure PP&L's system-wide future costs of operating with SSES 2 relative to its system-wide future costs of operating with another baseload supply alternative that provided essentially identical generating and capacity benefits to the system. However, this analysis requires only a comparison between the incremental differences in PP&L's future revenue requirements arising from the substitute coal-fired plant relative to retaining SSES 2. This incremental methodology is the standard one used in economic benefits analysis <u>and has frequently been used by Mr. Kahal</u> [footnote omitted] (emphasis added).

Significantly, Dr. Hieronymus' coal-proxy analysis is fully consistent with the manner in which the Commission has applied Section 1323(a)'s "economic benefits" test in the past (PP&L St. 16-R, p. 54). <u>See</u>, <u>e.g.</u>, <u>Pa. P.U.C. v. Pennsylvania Power Co.</u>, 93 PUR4th 189 (1988); <u>Pa. P.U.C. v. Philadelphia Electric Co.</u>, 74 Pa. P.U.C. 1 (1990). This is not to say that PP&L believes Section 1323(a) applies in this case as it did in those prior proceedings. However, if an evaluation of the economics of SSES 2 is to be meaningful, it must take into account the realistic alternatives that would have been available to PP&L.

Unlike Mr. Kahal's market-based approach, Dr. Hieronymus' analysis is not dependent upon speculation regarding the possible deregulation of the electric utility industry. To the contrary, his calculations are straight-forward and verifiable. Perhaps for this reason, Mr. Kahal did not contest any of Dr. Hieronymus' input assumptions and, accordingly, his findings were not seriously challenged. The results of Dr. Hieronymus' base case analysis, which are set forth in PP&L Exhibit WHH-4, were summarized as follows (PP&L St. 16-R, p. 58):

> I find SSES 2 provides annual net economic benefits to PP&L ratepayers in the test year and in virtually all years thereafter. Exhibit WHH-4 summarizes my findings. Under the most conservative assumptions, I find that PP&L rates are $4 million to $93 million lower per year with SSES 2 than with the alternative coal plant; under these assumptions, the only exception is in 1997, when SSES 2 yields slightly higher revenue requirements than does the coal plant.

In his base case analysis, Dr. Hieronymus assumed that 50% of all capital additions to SSES in 1989 and thereafter were attributable to SSES 2. As he explained, this is a very conservative assumption in light of a previous study commissioned by PP&L which indicated that only 27% of SSES's original common plant costs were truly incremental to SSES 2. Dr. Hieronymus therefore reran his initial calculations inputting the 27% common plant ratio. This sensitivity analysis produced annual net benefits from SSES 2 over the coal plant of $20 to $121 million (PP&L St. 16-R, p. 59).

Finally, Dr. Hieronymus performed a second sensitivity analysis to determine how his findings would change if SSES had been depreciated on a straight-line basis in the past, rather than on the modified sinking fund method which, after all, was only adopted to minimize PP&L's requested rate increase in the Unit 2 Case. What he found was that, under that scenario, the benefits of SSES 2 during the 1995-1998 period relative to the coal plant would have been approximately $50 million to $60 million higher than his base case results (PP&L St. 16-R, p. 59).

As noted previously, Mr. Kahal did not challenge the accuracy of Dr. Hieronymus' calculations. Instead, he claimed that Dr. Hieronymus' approach did not address the issue of economic excess capacity "in a meaningful way" because, based on what is known today, a coal plant might not be the "least cost replacement resource" (OCA St. 2A, p. 26). While this may be true, utilities do not plan, design, construct and integrate new capacity additions on an instantaneous basis. Rather, as Mr. Kahal later acknowledged (Tr. 2373), utilities must plan in advance and, in doing so, may properly be expected to rely on the best information available at the time.

Viewed from this perspective, the differences between Dr. Hieronymus and Mr. Kahal are clearly drawn. In his analysis, Dr. Hieronymus presumed that PP&L, in order to meet a perceived capacity need in 1995, would have initiated action in the mid to late 1980s to satisfy that need. In contrast, Mr. Kahal implicitly assumed that the Company would have sat on its hands until 1995 and then looked around to determine what its least-cost option might be. PP&L submits that there can be little doubt as to which approach is more "meaningful".

d. Summary

The record in this proceeding establishes that PP&L now needs SSES 2 to meet its customers' demands and maintain a reasonable reserve margin. In addition, to the extent at all relevant, the Company has demonstrated that SSES 2 produces annual benefits when compared to the cost of a logical baseload alternative. The excess capacity adjustments proposed by the OTS and OCA should, therefore, be rejected.

B. Accrued Depreciation

The Company's claim for accrued depreciation related to its utility plant in service was developed by Mr. Donald S. Hoch, Supervisor - Plant Accounting for PP&L, and is summarized in Schedule C-2, page 2, of PP&L Exhibit Future 1 - Revised. Detailed calculations are set forth in the Company's response to the Commission's filing regulation V-A-3.

PP&L's book reserve was adopted as the appropriate measure of accrued depreciation for ratemaking purposes pursuant to the Commission's Final Order at Docket No. R-842651. Mr. Hoch computed the accrued depreciation related to PP&L's plant in service as of September 30, 1995 by reflecting all appropriate entries required to establish what the Company's book reserve would be at that point in time (PP&L St. 4, p. 7). No party has disputed the Company's claim for accrued depreciation.

C. Additions To Rate Base

In addition to the depreciated original cost of utility plant in service, PP&L has included, in its claimed rate base, its investment in pollution control construction work in progress ("CWIP"), fuel stocks and materials and supplies. Although PP&L has made no claim for cash working capital, witnesses for the OTS and the OCA have proposed adjustments to reduce the Company's claimed rate base to reflect alleged "negative" cash working capital. As fully explained below, the Commission, with the affirmance of Pennsylvania's Appellate Courts, has consistently refused to adopt a negative cash working capital allowance.

1. Pollution Control Projects

The Company's rate base claim includes expenditures of $12,723,000 for CWIP related to various pollution control projects. Associated retirements of $345,000 were deducted from rate base, resulting in a net rate base addition, on a Pennsylvania jurisdictional basis, of $12,378,000 (PP&L Ex. Future 1 - Revised, Sch. C-1). The individual pollution control projects included in the Company's claim are detailed in Schedule C-4 of PP&L Exhibit Future 1 - Revised. As explained by Mr. Douglas A. Krall, Manager-Integrated Resource

Planning for PP&L, these projects are needed to satisfy State and Federal air and water pollution control regulations and are neither revenue-producing nor expense-reducing (PP&L St. 5, pp. 8-9). As a consequence, the amount of CWIP claimed by PP&L is properly includable in its rate base in this case pursuant to Section 1315 of the Public Utility Code (66 Pa.C.S. §1315) and prior Commission precedent. See, e.g., Pa. P.U.C. v. Metropolitan Edison Co., 141 PUR4th 336, 346-350 (1993); Pa. P.U.C. v. Duquesne Light Co., 66 Pa. P.U.C. 518, 661 (1988). No party has disputed the Company's pollution control CWIP claim.

2. Fuel Stocks And Materials And Supplies

The Company must store an adequate supply of fuel (coal and oil) at its fossil-fired generating stations. The Company's rate base claim in this case includes its estimated investment in fuel stocks as of September 30, 1995, which was calculated based on the Company's normal fuel inventory levels and projected inventory prices (PP&L St. 3, p. 13; PP&L Ex. Future 1 - Revised, Sch. C-5).

The Company must also maintain an inventory of materials and supplies in order to have available items needed to operate, repair and maintain facilities used to provide electric service. Accordingly, the Company's rate base claim includes its estimated average investment in materials and supplies for the twelve months ending September 30, 1995 (PP&L St. 3, p. 13; PP&L Ex. Future 1 - Revised, Sch. C-5).

The Company's claim for fuel stocks and materials and supplies totalling $188,808,000 has been developed in a manner consistent with Commission-approved procedures and prior precedent, and that claim has not been contested by any party in this case.

3. Cash Working Capital

PP&L has made no claim for cash working capital in this proceeding. However, in compliance with the Commission's filing requirements, the Company had included with its supporting data a detailed cash working capital study. That study employed the lead-lag method to calculate the amount of Company-provided funding required because, on average, operating and maintenance expenses for each monthly service period must be paid before the Company receives revenues from customers. In addition, Company funds used for prepayments, which are not reflected in the lead-lag study, were also analyzed. In accordance with Commission policy, the Company also calculated amounts representing the offsetting effect on its cash working capital requirements of interest on long-term debt and dividends on preferred stock that purportedly accrue prior to pay-out.

a. Negative Cash Working Capital Should Not Be Recognized

Mr. Charles T. Weakley, on behalf of the OTS, and Mr. Thomas S. Catlin, on behalf of the OCA, proposed revisions to the Company's lead-lag analysis and calculation of average prepayments designed to reduce PP&L's indicated cash working capital requirement. In the absence of a PP&L claim for cash working capital, the revisions proposed by the OTS and the OCA should have had no practical consequence in this case. However, because the proposed adjustments, if adopted, would yield a positive cash working capital requirement that is <u>less</u> than the "off-set" for accrued interest and preferred stock dividends, Messrs. Weakley and Catlin recommended that the Commission adopt a <u>negative</u> cash working capital allowance, i.e., that PP&L's rate base be <u>reduced</u> by the excess of the interest and dividend "off-set" over PP&L's positive cash requirements.[22] Such adjustments are conceptually flawed, contrary to Commission precedent and should be rejected.

As explained by Mr. Ronald J. Bernini, Manager-Regulatory Accounting for PP&L, the "off-set" for accrued interest and dividends is not a "stand alone" component of a utility's rate base because it cannot exist except in relation to a claim for a positive cash working capital allowance. Accordingly, the "off-set" should not be used to reduce a utility's rate base below the amount of positive cash working capital actually claimed for rate base inclusion (PP&L St. 3-R, p. 2):

> On balance, I believe the Company provides service to customers in advance of receipt of revenues less the lag in payment of expenses.

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[22] Mr. Weakley and Mr. Catlin proposed rate base reductions of $12,270,000 and $6,157,000, respectively (OTS St. 4, p. 43; OCA St. 6, Sch. TSC-2)

> The bond interest offset should be just that -- an "offset" -- to cash working capital and should not be used to reduce working capital below zero.

Significantly, the Commission has consistently refused to reduce a utility's rate base for an alleged negative cash working capital requirement and, instead, has simply adopted a cash working capital requirement of zero. See, e.g., Pa. P.U.C. v. Pennsylvania Power Co., 67 Pa. P.U.C. 91, 129 (1988) ("[N]o rational basis exists for a negative CWC allowance . . ."); Pa. P.U.C. Duquesne Light Co., 66 Pa. P.U.C. 518, 654 (1988)("If the final calculation of a CWC allowance results in a negative number, DLC's CWC allowance will be set no less than zero.")[23/]

Additionally, as previously indicated, the Commonwealth Court has twice affirmed the Commission's determination that a negative cash working capital allowance is not proper. Barasch v. Pa. P.U.C., 111 Pa. Cmwlth. 339, 349-50, 533 A.2d 1108, 1112-13 (1987); Barasch v. Pa. P.U.C., 108 Pa. Cmwlth. 326, 331-32, 530 A.2d 936, 938-39 (1987).

[23/] Accord Pa. P.U.C. v. Pennsylvania Power Co., 85 PUR4th 323, 362 (1987); Pa. P.U.C. v. Quaker State Telephone Co., 72 PUR4th 503, 514 (1986); Pa. P.U.C. v. Continental Telephone Co. of Pa., 61 Pa. P.U.C. 46 (1986); Pa. P.U.C. v. Equitable Gas Co., 60 Pa. P.U.C. 127, 141 (1985); Pa. P.U.C. v. Pennsylvania Power Co., 27 PUR4th 426, 432 (1978); Pa. P.U.C. v. Mid-Penn Telephone Corp., 52 Pa. P.U.C. 405, 412-13 (1978); Pa. P.U.C. v. Allegheny County Steam Heat Co., 19 PUR4th 422, 430 (1977).

For the reasons set forth above, PP&L's rate base should not be reduced to reflect alleged negative cash working capital.

b. Miscellaneous Adjustments To PP&L's Cash Working Capital Analysis

Although Messrs. Weakley and Catlin each proposed a variety of miscellaneous adjustments to the Company's analysis of its operating cash needs, the revisions that account for the bulk of their proposed reduction in cash working capital relate to prepayments. In addition, Mr. Catlin proposed a separate lag calculation for Clean Air Act Amendment ("CAAA") permit fees, which would have a material effect on the lead-lag analysis. For the reasons explained above, it should not be necessary to address these proposed revisions. Nonetheless, it must be noted that both of the major adjustments to the Company's cash working capital analysis recommended by the OTS and the OCA are incorrect and should be rejected on their merits.

<u>Prepayments</u>. Messrs. Weakley and Catlin proposed to eliminate prepayments associated with postage, insurance and other items from the calculation of the Company's operating cash requirements on the grounds that they are duplicative of expenses already reflected in the Company's lead-lag study (OTS St. 4, p. 50; OCA St. 6, pp. 7-9). That contention is factually incorrect. As Mr. Bernini explained, unless the prepayments are separately reflected in the cash working capital analysis, the

need for Company funds which they impose would not be recognized (PP&L St. 3-R, p. 3):

> Prepayments are recorded as an asset on the Company's balance sheet and, as such, do not appear in the operation and maintenance expenses included in the lead-lag study. These prepayments, e.g., insurance and postage, are paid in advance of the recording of the applicable expense on PP&L's books. These prepayments remain on the balance sheet until expensed, and therefore are not reflected in the expense lag study. The average prepayment balance and the operating expense are two separate and distinct items. There is no double counting, because the prepayment balance was not included in the expense balance.
>
> I also would note that the approach utilized by the Company is identical to that used in prior PP&L rate cases and accepted by the Commission.

CAAA Permit Fees. OCA witness Catlin has proposed an adjustment to the expense lag calculation used in the Company's lead-lag study that would: (1) separately analyze the payment pattern for CAAA permit fees; and (2) assign that expense a lag of 421 days. Both aspects of Mr. Catlin's proposal are improper and, as a result, the expense lag adjustment he recommends should be rejected.

In accordance with accepted procedures for lead-lag studies, the Company separately analyzed payment patterns for each major component of its expenses, such as wages and salaries, fuel by type and purchased power by source. Various general expenses that did not fall into one of the recognized categories were treated a category unto themselves. Because of the size of this grouping and the large number of different expenses it includes, PP&L's average expense lag was derived based on a representative, random sample. The expense lag thus calculated was used as a proxy for the category as a whole (PP&L St. 3-R, p. 5).

Mr. Catlin did not take issue with the use of a sampling technique to calculate the expense lag for general expenses. Neither did he dispute the size, composition or statistical validity of the sample employed by PP&L. Rather, he simply plucked out a single expense -- CAAA permit fees -- for separate analysis because he believed its payment lag was significantly longer than the average for the entire category. Mr. Catlin's approach is totally inconsistent with the use of sampling and averaging techniques to determine a reasonable expense lag proxy for a broad general category of expenses. As Mr. Bernini explained, Mr. Catlin simply "cherry-picked" a single expense with a presumed longer than average lag, while ignoring the fact that there are undoubtedly a host of other expenses of the same or similar magnitude with payment lags significantly <u>shorter</u> than the average. For that reason alone, Mr. Catlin's adjustment is incorrect and should be rejected.

Additionally, Mr. Catlin has misconstrued the payment pattern associated with CAAA permit fees. Those payments are made in advance, not in arrears as he assumed. As Mr. Bernini explained, the Pennsylvania Department of Environmental Resources ("DER"), which is responsible for administering the CAAA, operates on a July 1 to June 30 fiscal year. The CAAA payment made in August 1994 related to DER's July 1, 1994 to June 30, 1995 fiscal year. Indeed, that has to be the case for DER to have sufficient funds to run the CAAA program. As a consequence, December 31, 1994 is the mid-point of the service period, and the August 26, 1994 payment date results in a negative lag -- or lead -- of 120 days (PP&L St. 3-R, p. 4).

Mr. Catlin also proposed a 421-day lag because he apparently confused the time frame of data used to calculate the CAAA permit fee with the application period to which the permit relates. As Mr. Bernini explained, the amount of the permit fee is calculated on the basis of historical data, but the permit itself applies to a prospective period.[24/] In this respect, the permit fees are like the PUC assessment, which applies to a current fiscal year, but is calculated on the basis of a utility's historical revenues. Mr. Catlin acknowledged that the PUC assessment is paid in advance, but drew a totally different conclusion as to CAAA permits notwithstanding a virtually identical factual scenario.

In summary, CAAA permit fees should not be singled out for a separate expense lag analysis. However, if they are, that

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[24/] A "permit," by its very nature, is an authorization of some <u>future</u> activity or conduct. There is simply no evidence that CAAA permits constitute a unique, "after-the-fact" authorization of prior-period emissions.

analysis shows a <u>lead</u> of 120 days, not a lag of 421 days as Mr. Catlin contends.

D. <u>Deductions From Rate Base</u>

In accordance with the Uniform System of Accounts for Electric Utilities and Licensees prescribed by the FERC and adopted by the Commission, contributions-in-aid-of-construction ("contributions") are deducted from the original cost of utility plant recorded in the Company's property records. Accordingly, the depreciated original cost of utility plant does not include any amount funded by contributions, and a separate rate base deduction for contributions is not required. In accordance with applicable ratemaking procedures, the Company has made rate base deductions for accumulated deferred taxes, customer advances and customer deposits.

1. <u>Accumulated Deferred Taxes</u>

PP&L uses the Accelerated Cost Recovery System ("ACRS") and the Modified Accelerated Cost Recovery System ("MACRS") to calculate depreciation deductions on post-1980 property additions for income tax purposes. As required by the Internal Revenue Code, PP&L normalizes the federal income tax effects of the use of ACRS and MACRS for book and ratemaking purposes. The resulting accumulated deferred taxes, as projected to September 30, 1995, have been deducted from the Company's rate base, as shown on Schedule C-1 of PP&L Exhibit Future 1 - Revised (PP&L St. 3, pp. 13-14).

2. Customer Advances And Customer Deposits

Customer advances for construction ("advances") are amounts advanced for the extension of Company facilities or similar construction which are subject to refund. Advances are recorded in Account 252 until the termination of the period during which some portions thereof may be refundable under applicable tariff provisions and service contracts with the depositor. The estimated balance of Account 252 at September 30, 1995 was deducted from the Company's claimed future test year rate base (PP&L St. 3, p. 14; PP&L Ex. Future 1 - Revised, Sch. C-1).

The Company also receives and holds deposits from customers as permitted by its tariff and applicable Commission regulations. In its Final Order at Docket No. R-80031114, the Commission prescribed that customer deposits be deducted from rate base and that the Company claim the interest payable thereon as an operating expense. Accordingly, the estimated balance of customer deposits at September 30, 1995 was deducted from the Company's rate base in this case (PP&L St. 3, p. 14; PP&L Ex. Future 1 - Revised, Sch. C-1). The applicable interest includable in the Company's pro forma expenses is discussed in Section V., <u>infra</u>.

E. Accrued Pension Liability As A Rate Base "Offset"

OCA witness Catlin proposed an adjustment to reduce the Company's rate base by $74 million to reflect PP&L's accrued pension liability at September 30, 1995. That amount represents the difference between the pension costs the Company recorded on its books as an expense for financial reporting purposes pursuant to Statement of Financial Accounting Standards No. 87 ("SFAS-87") and PP&L's cash contributions to its pension plan since the implementation of SFAS 87. In substance, the premises underlying Mr. Catlin's proposed adjustment are: (1) the pension expense accrued under SFAS 87 for financial reporting purposes should be deemed to have been recovered by the Company; (2) to the extent that the sum of the accounting entries required by SFAS 87 exceeds PP&L's actual cash contributions to its pension plan since the adoption of SFAS 87, the Company has received customer-supplied funds; and (3) because those funds have not been paid into the pension plan, they are available for Company use and should be reflected as no-cost capital supporting its rate base (see OCA St. 6, p. 5). Mr. Catlin's argument is flawed in several significant respects.

First, it is incorrect to assume, as Mr. Catlin has done, that accounting entries made for financial reporting purposes are the same as cash actually recovered through rates charged to customers. Significantly, prior to 1987, generally accepted accounting principles prescribed that a company's pension expense for financial reporting purposes could be the same as the cash contributions it made to its pension plan (PP&L St. 2-R, pp. 11-12). Except for the change in pension accounting rules brought about by SFAS 87, PP&L would have recorded as an expense only its actual pension plan contributions; no "accrued pension liability" would have been booked under SFAS 87; and the entire basis for Mr. Catlin's proposed rate base adjustment would have ceased to exist. Is it possible that, with no increase in rates, a change in pension accounting rules alone would suddenly begin to generate customer-supplied funds that could be used to finance the Company's rate base? Merely stating that proposition -- which is the premise of Mr. Catlin's proposed adjustment -- underscores the fallacy at the heart of his theory.

Secondly, pension liability was "accrued" on the Company's balance sheet because it represents an expense booked but not paid. When applicable Internal Revenue Code regulations permit a cash contribution to be made to the pension plan, which will occur as early as the third quarter of 1996, the accrued liability will begin to be reversed in amounts equal to the cash contributions (PP&L St. 2-R, pp. 12-14). As a practical matter, this means that the "accrued pension liability" represents an amount by which the Company's pension plan is <u>underfunded</u> on a actuarial basis, not <u>overfunded</u> as Mr. Catlin's discussion of this issue would suggest (PP&L St. 2-R, p. 14). In reality, Mr. Catlin is proposing a rate base deduction because the Company, in effect, owes $74 million to the pension trust.

Clearly, adopting a rate base deduction under those circumstances makes no sense.

Mr. Catlin, recognizing the numerous defects in the justification he originally offered for his proposed $74 million rate base deduction, changed the focus in his surrebuttal testimony from the pension expense accrued under SFAS 87 to the pension costs allowed as an expense in the Company last base rate case. In that proceeding, which was concluded in 1985, the Company's claim was based on its cash contribution to the pension plan for the future test year, which was about $19.1 million. Since that time, the amounts actually contributed to the plan declined significantly. Mr. Catlin therefore suggested that his proposed rate base deduction be adopted as a "true-up" of the difference between the pension expense included in the Company's rates in its last case and the actual pension expense incurred during the period those rates were in effect (OCA St. 6A, pp. 4-5). This argument is as seriously flawed as Mr. Catlin's original rationale.

First, any attempt to "true-up" elements of a prior base rate determination with a utility's actual expenses is improper as a matter of law, as Pennsylvania's Appellate Courts have repeatedly held:

> The general rule is that there may be no line by line examination of the relative success or failure of the utility to have accurately projected its particular items of expense or revenue and an excess over the projection of an isolated item of revenue or expense may not be, without more, the subject of the Commission's order of refund or recovery, respectively, on the occasion of the utility's subsequent rate increase requests.

Philadelphia Electric Co. v. Pa. P.U.C., 93 Pa. Cmwlth. 410, 422, 502 A.2d 722, 727-28 (1985). Accord Pike County Light & Power Co. v. Pa. P.U.C., 87 Pa. Cmwlth. 451, 487 A.2d 118 (1985)("The Commission clearly may not establish rates which are calculated to retroactively recover surpluses or refund deficits created by inaccuracies in its prior rate authorizations.")

Second, by focusing on pension expense as the basis for a "true-up," Mr. Catlin has engaged in selective analysis to the detriment of the Company. As explained by Mr. Michael J. Berish, Manager-Financial Planning for PP&L, during the period that pension expense, as measured by contributions to the plan, were declining, other categories of employee benefit expense were running far above the levels included in PP&L's existing rates (PP&L St. 2-R, p. 15):

> While pension expense has declined, medical expenses and the cost of other benefits have increased dramatically since the Company's last rate case. Specifically, as shown on Exhibit MJB-15, medical costs have increased from $14 million to $49 million, and total benefits have increased from $52 million to $93 million. It is unfair for Mr. Catlin to focus on pensions without considering changes in other benefits.

In summary, the attempt to "true-up" pension expense with the amount claimed in the Company's last rate case, which is the real nature of Mr. Catlin's proposed rate base offset for accrued pension liability, is improper, inequitable and unlawful, and should be rejected.

F. Land Held For Future Use

PP&L has included no plant held for future use in its future test year rate base claim in this case. Instead, it is requesting Commission approval: (1) to begin accruing a return component, equivalent to the applicable Allowance For Funds Used For Construction ("AFUDC"), on plant held for future use; and (2) to be permitted to include the accrued amounts as part of its original cost at the time the plant to which the accruals relate is actually placed in service. The Company's request is consistent with the treatment accorded future use property by the Commission for other utilities, as explained in Pa. P.U.C. v. West Penn Power Co., 73 Pa. P.U.C. 454, 463 (1990):

> Barasch v. Pa. P.U.C., 516 Pa. 142, 95 PUR4th 521, 532 A.2d 325 (1987), aff'd sub nom. Duquesne Light Co. v. Barasch, 488 U.S. 299, 98 PUR4th 253, 102 L.Ed.2d 646, 109 S.Ct. 609 (1989) prohibits inclusion of [West Penn's] claim for plant held for future use in the rate base. Since Barasch, however, the Commission has permitted companies to accrue carrying charges equivalent to AFUDC on their investments in land held for future use. Pa. P.U.C. v. Pennsylvania Power Co., 67 Pa. P.U.C. 91, 127, 93 PUR4th 189 (1988), Pa. P.U.C. v. Pennsylvania-American Water Co., 68 Pa. P.U.C. 343, 354, 97 PUR4th 469 (1988), and Pa. P.U.C. v. Philadelphia Electric Co., Docket R-891364, April 19, 1990 [74 Pa. P.U.C. 1, 126-27].

Mr. Paul J. Metro, on behalf of the OTS, opposed the Company's request to accrue AFUDC-equivalent charges on future use property (OTS St. 5, pp. 28-30). Mr. Metro's opposition appears to be based upon his mistaken belief that PP&L is requesting a current determination that all accrued amounts will be properly includable in rate base in future rate proceedings. Significantly, when the OTS interposed a comparable objection to Philadelphia Electric Company's request for similar accounting approval, it was rejected. <u>See</u> <u>Pa. P.U.C. v. Philadelphia Electric Co.</u>, 74 Pa. P.U.C. 1, 126-27 (1990).

The Company is requesting approval in the nature of an accounting order to permit the accrual of AFUDC-equivalent amounts on its books. When these costs are claimed in rate base in future rate proceedings, all parties will have the opportunity to review the prudence and reasonableness of the Company's investment in new plant. It is not intended that the accounting approval requested herein will preclude the examination of such issues in the future. As a consequence, there is no basis for OTS' opposition to the Company's request.

IV. REVENUES

In this proceeding, the Company submitted extensive financial and accounting data depicting the results of its operations both during the historic test year ended September 30, 1994 and as projected for the future test year ending September 30, 1995. A summary statement of income showing the Company's revenue and expense claims is provided in Appendix B.

To calculate pro forma future test year revenues under existing rates, the Company began with a future test year revenue level taken directly from the Company's operating budget (PP&L St. 8, p. 4). The Company then adjusted this figure to reflect the annualization of sales and revenues, the roll-in of the energy only portion of the ECR, the roll-in of the Atlantic City Electric portion of the SBRCA, and the roll-in of the expected STAS of -0.49% into base rates for the year ending September 30, 1995. The Company's final pro forma revenue claim is $2,462 million (PP&L Ex. Future 1-Revised, Sch. D-3 p. 5).

Three adjustments were proposed to the Company's claim. Several parties proposed to increase revenues to reflect a reduction in the interest paid on customer deposits in accordance with a revision to the Commission's regulations adopted shortly after the Company's filing. The Company agreed to make this adjustment, which has been incorporated into Exhibit Future 1 - Revised.

The OCA proposes to increase revenues by $12.7 million to reflect a disallowance of one-half of the credits from the Company's economic development initiatives (OCA St. 5, p. 17). This adjustment should be rejected for the reasons set forth in Section VIII, infra.

The Oil Dealers present alternative proposals relating to Rate RTS that would require the Company's shareholders to absorb alleged revenue deficiencies generated by this rate class. The many errors and inconsistencies in the Oil Dealers' proposal are addressed at length in Section VIII, infra, and should be summarily rejected.

V. **EXPENSES**

A. Operating And Maintenance Expenses

Claimed Pennsylvania jurisdictional operating and maintenance expenses for the twelve months ending September 30, 1995 equal $1,375,408,000 (PP&L Ex. Future 1 - Revised, Sch. D-1, p. 1). The reasonableness of all expense claims has been demonstrated through extensive documentation provided in the Company's filing data (see generally PP&L Ex. Future 1 and PP&L Ex. I, Vols. 2 and 6) and through detailed explanation of all adjustments by Messrs Berish (PP&L Sts. 2 and 2-R) and Bernini (PP&L Sts. 3 and 3-R). Further supporting information was provided throughout the course of this proceeding in response to numerous interrogatories and data requests propounded by the OTS, OCA and various other parties.

The discussion below addresses those expense claims which have been contested by one or more of the opposing parties.

1. Voluntary Early Retirement Program Savings

In an effort to reduce its operating costs, the Company announced a Voluntary Early Retirement Program ("VERP") on September 25, 1994. This program allowed eligible employees to select early retirement without a substantial reduction in retirement benefits.[25] The Company's initial filing included a net reduction in operating expense of $13,917,000 as a result of the VERP (PP&L St. 2, p. 14). This adjustment reflected the anticipated annual savings from wages and benefits ($27.1 million) less the anticipated cost ($65.8 million) amortized over five years (PP&L St. 2, pp. 13-14).[26]

As indicated in Mr. Berish's direct testimony, the VERP cost and savings figures included in the Company's original filing were estimates based on the number of employees who were anticipated to select the VERP. PP&L subsequently provided an updated calculation of its total VERP costs and payroll savings based on actual data in response to OCA Interrogatory, Set IV,

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[25] As explained by Mr. Berish, the VERP included the following components (PP&L St. 2, pp. 12-13):

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

- To offset the normal reduction in pension benefits if employees retire before age 62, 100% of the employees' accrued retirement benefit as of the date of retirement.

- To provide for a transition into retirement, a lump-sum payment at retirement of one week's pay for each year of service.

[26] $27.1 million - ($65.8 million ÷ 5) = $13.9 million.

No. 75 (PP&L St. 2-R, p. 17). The Company's final total reflects a net reduction in operating expenses of $12,742,000 (PP&L Ex. Future 1 - Revised, Sch. D-10), or $11,029,000 on a PUC jurisdictional basis.

DOD witness Prisco proposed to increase PP&L's original adjustment by an additional $3.2 million, for a total net reduction of $17,128,000 (DOD St. 1, p. 8). Mr. Prisco calculated his proposed adjustment using the estimated data in the Company's initial filing (Id.). On cross-examination, Mr. Prisco testified that he had not reviewed the information submitted by PP&L regarding actual VERP costs or the salaries of the employees who retired under the program (Tr. 1466-67). Mr. Prisco conceded, however, that it would be appropriate to determine VERP costs using the actual salaries for employees who retired rather than an average salary figure (Tr. 1467). Mr. Prisco therefore should have no objection to the Company's updated claim.

PP&L's VERP claim also was opposed by PPLICA witness Kollen and OCA witness Catlin.[27] Messrs. Kollen and Catlin both contend that the wage savings realized from the effective date of the VERP (December 31, 1994) to the date that new rates go into

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[27] Mr. Catlin's initial testimony on the VERP correctly pointed out that the Company had not fully reflected the benefit savings from the VERP (OCA St. 6, p. 13). In response to OCA Interrogatory Set IX, No. 29, the Company agreed and has reflected the additional savings in its final accounting exhibit.

effect (October 1, 1995) should be used to offset the costs of the program (PPLICA St. 2, pp. 26-29; OCA St. 6A, p. 6). Mr. Kollen further argues that VERP costs should be amortized over ten years, rather than the five-year period proposed by the Company. These recommended adjustments, which would collectively reduce the Company's revenue requirement by $9.564 million (PPLICA St. 2, pp. 27, 29) are without merit and should be rejected for a number of reasons.

First, and most significantly, the VERP has not produced the cost savings which Messrs. Kollen and Catlin would impute. As Mr. Berish explained (Tr. 2048-2049):

> Q: Returning to Mr. Catlin's statement at page 7 that the implementation of the VERP has produced cost savings, has that in fact been the company's experience to date?
>
> A: No, sir, it has not to date. We would anticipate that [VERP] would produce savings into the future, but as a practical matter, when 640 people leave the company within a relatively short period of time, the work that they were doing does not correspondingly leave the company.
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> * * *
>
> [W]e have had to supplement our work force with either additional overtime of the employees that we have, we have had to hire some additional temporary employees, we have had to contract out some work until we get into the position where we can in fact eliminate the work and as a result provide the cost savings that we anticipated as a result of the voluntary early retirement program.

Since the imputed cost savings have not been generated to date, there is no basis for the PPLICA/OCA adjustment.

Second, the Company has already reflected a full year of VERP savings in its rate filing. It would be inappropriate to reflect additional savings resulting from regulatory lag between the effective date of the VERP and the effective date of new rates. While some modest level of VERP savings may be realized later in the future test year, the Company also will experience increased operating expenses and plant additions during the same period. None of these increased costs will be recognized and reflected in rates until the Commission enters a final order in this case (PP&L St. 2-R, p. 18).[28] It would therefore be improper and inconsistent to recognize an isolated decrease in operating expense during the future test year without also recognizing off-setting cost increases.

Finally, the ten-year amortization period recommended by PPLICA is inconsistent with the Commission's general treatment of similar costs (PP&L St. 2-R, p. 18). In Pennsylvania, the Commission does not permit utilities to earn a return on the

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[28] For example, the Company begins to depreciate new plant when that plant goes into service. The amount included in rates is the net plant at the end of the future test year. Thus, if a new facility goes into service on April 1, 1995, the Company will begin to depreciate that facility at that time. The amount reflected in rates will be the net plant balance at September 30, 1995, the end of the future test year. The six months of accrued depreciation is never recovered from customers. Similarly, if the Company begins to incur an increased expense on April 1, 1995, that expense is reflected in rates at an annualized level when new rates take effect. There is no recovery of the costs incurred from April 1 - September 30, 1995. The same rationale should apply to the regulatory lag for VERP savings, i.e., they should be reflected at an annualized level when new rates take effect.

unamortized balance of an expense amortization. See, e.g., Butler Township Water Co. v. Pa. P.U.C., 81 Pa. Cmwlth. 40, 47-48, 473 A.2d 219, 223 (1984); Pa. P.U.C. v. National Fuel Gas Distribution Corp., 72 Pa. P.U.C. 1, 26-27 (1989). For this reason and others, the Commission has generally adopted three to five-year amortization periods. Longer amortizations, such as the ten-year period proposed by PPLICA, could deny recovery of a portion of the underlying costs on a present value basis. This is clearly inappropriate. The Company's proposed five-year amortization period therefore should be approved.

2. Pension Expense

The Company's final total for pension costs is $11,867,000 and represents the amount that PP&L will accrue on its books during the future test year (PP&L Ex. Future 1 - Revised, Sch. D-6).[29] On a Pennsylvania jurisdictional basis, PP&L is requesting recovery of $6,776,000 in pension costs charged to operating expense, and rate base capitalization of $3,221,000.

Both the OTS and the OCA propose the complete disallowance of PP&L's pension expense claim. Their recommendations, however,

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[29] PP&L calculated its initial amount of pension expense of $17,898,000 based on a 1994 actuarial study performed by its outside actuary, Towers Perrin. The Company adjusted this estimate to account for pension plan changes and to increase the discount rate used in the study from 7.0% to 7.25%. On March 21, 1995, PP&L submitted a 1995 actuarial report in which the discount rate was raised even further to 7.5%. The Company's final claim was calculated using this updated information (PP&L Ex. Future 1 - Revised, Sch. D-6).

rest on different grounds. The OTS asserts that the Company's claim should be denied because PP&L will not be making any cash contributions to its pension fund during the future test year (OTS St. 4, pp. 13-15). The OCA, on the other hand, contends that PP&L has overstated the costs to be accrued under Statement of Financial Accounting Standards No. 87 ("SFAS 87") by using an unreasonably conservative discount rate (OCA St. 6, pp. 15-17).[30] As explained below, these proposed adjustments lack merit and should be rejected.

a. PP&L's Treatment Of Pension Expense On An Accrual Basis Should Be Approved

As recognized by OTS witness Weakley, PP&L is required to undertake two different pension expense calculations each year. In accordance with Generally Accepted Accounting Principles ("GAAP"), SFAS 87 requires the Company to accrue pension expenses on its books and to adjust those costs at year-end to an actuarially determined amount. The Company also is required to calculate the amount of its annual pension fund contributions in accordance with ERISA and IRS rules (OTS St. 4, pp. 11-12). PP&L's pension expense claim in this proceeding is based on its calculation of accruals under SFAS 87.

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[30] As discussed in Section V.3, infra, the OCA also claims that the Company has used an overly conservative discount rate in calculating its claim for other post-retirement benefits costs.

Mr. Weakley argues that, for ratemaking purposes, pension expense should be determined based on actual cash contributions rather than expenses accrued under SFAS 87 (OTS St. 4, p. 13). Specifically, Mr. Weakley contends that PP&L's entire claim should be disallowed because no actual cash contributions will be required during the future test year (OTS St. 4, pp. 14-15). Mr. Weakley's recommended adjustment should be rejected for several reasons.

First, Mr. Weakley's proposed treatment of pension expense likely will result in extremely variable costs from year to year. As explained by Mr. Berish, most pension funds were immature and unfunded until the mid 1980's. However, the IRS subsequently has limited contributions to well-funded plans and accelerated contributions to under-funded plans. PP&L's cash contribution requirements therefore could vary substantially in the future under ERISA and IRS rules (PP&L St. 2-R, pp. 11-12).

SFAS 87, in contrast, facilitates the calculation of reasonably stable levels of pension expense from year to year (PP&L St. 2-R, p. 12). Under SFAS 87, asset values generally rise when interest (discount) rates decline. Conversely, asset values usually fall when interest (discount) rates increase. Thus, the overall effect of SFAS 87 is to preserve a reasonable balance between assets and obligations. By recognizing pension expense as determined under SFAS 87, PP&L can successfully "normalize" such costs for ratemaking purposes (PP&L St. 2-R,

p. 12). In fact, a comparison of SFAS 87 costs and cash contributions from 1987 through 1998 demonstrates that SFAS 87 costs are far more stable and, perhaps more importantly, would produce a lower revenue requirement and hence lower rate levels over the next several years (PP&L St. 2-R, p. 12; PP&L Ex. MJB-14).

Second, Mr. Weakley's proposal is inconsistent with this Commission's adoption of SFAS 106 for the purposes of determining ratemaking allowances for other forms of post-retirement benefits. As discussed in Section V.3, infra, the Commission presently allows utilities to claim other post-retirement benefit costs on an accrual rather than cash basis. It makes no sense, from a ratemaking standpoint, to calculate pension expense on a cash basis, but calculate retirement benefits other than pensions on an accrual basis. The Company's claim is fully consistent with the Commission's position on SFAS 106 and should be approved.

Finally, PP&L's claim is wholly consistent with prior Commission precedent. In Pa. P.U.C. v. West Penn Power Co., Docket No. R-00942986, 1994 Pa. PUC LEXIS 144 (Order entered December 29, 1994)("West Penn"), the utility requested an increase in operating expenses for pension costs determined in accordance with SFAS 87. Both the OTS and the OCA opposed West Penn's claim, arguing, inter alia, that pension expense should continue to be determined based on actual cash contributions in accordance with the Commission's Order in a prior case. See, Pa. P.U.C. v. West Penn Power Co., 73 Pa. P.U.C. 454 (1990).

The ALJ rejected the OTS' and the OCA's proposed adjustments and instead recommended approval of West Penn's claim. The ALJ concluded that SFAS 87 treatment was appropriate because: (1) West Penn would be required to make a cash contribution during the test year; and (2) cash contributions for each of the four years following the test year would exceed SFAS 87 requirements. The Commission agreed with the ALJ's recommendation and noted as follows (Order, p. 45):

> In addition, there is credible evidence in the record, that under the pay-as-you-go or cash basis the amount of payments are significantly higher than those calculated under the SFAS 87 methodology. The Company has offered to utilize the SFAS 87 method to lessen the rate burden on its present and future ratepayers. . . . While we are under no illusion that the SFAS 87 method does not afford some benefit to the Company in terms of accounting conformity and predictability, we would be remiss in our statutory obligation to reject a reasonable proposal which promotes the public interest.

PP&L's claim in the instant case is virtually identical to the claim approved by the Commission in West Penn. The record evidence demonstrates that PP&L currently intends to make a cash contribution to its pension fund as early as the third quarter of 1996, which is within the first year that the rates set in this case will be in effect (PP&L St. 2-R, p. 13). Moreover, as shown on PP&L Exhibit MJB-14, the Company anticipates that it will be required to make annual contributions each year thereafter. As in West Penn, PP&L's pension expense will be significantly higher when measured on a cash basis than on an accrual basis for each of the three years following the test year (PP&L Ex. MJB-14). PP&L's claim therefore should be approved.

b. The OCA's Proposed Discount Rate Is Inappropriate And Should Be Rejected

OCA witness Catlin argues that PP&L has overstated its pension expense claim by using an unduly low discount rate of 7.5% (OCA St. 6, pp. 15-16). After reviewing the yields on investment grade bonds as of December 31, 1994, Mr. Catlin recommended that a discount rate of 8.5% be utilized for purposes of calculating the Company's ratemaking allowance. In support of his proposal, Mr. Catlin noted that in Pennsylvania-American Water Company's ("PAWC") current rate proceeding, PAWC had updated its pension and post-retirement benefits claims to reflect a discount rate of 8.75% (OCA St. 6, p. 16). Utilizing his proposed discount rate of 8.5%, Mr. Catlin concluded that PP&L's claimed pension expense should be completely disallowed (OCA St. 6, pp. 16-17). Mr. Catlin's recommendation should be rejected for two reasons.

First, PP&L's selection of a 7.5% discount rate is completely consistent with SFAS 87 and SFAS 106. As PP&L witness Beers explained (PP&L St. 14-R, p. 2):

> [C]ontrary to the impression left by Mr. Catlin, the selection of an appropriate discount rate is not a mechanical process tied to specific capital cost levels, but rather requires the exercise of

> informed judgment based on a careful review of multiple factors. In this regard, [SFAS 87] provides that "[a]ssumed discount rates shall reflect the rates at which the pension benefits could be effectively settled" (Paragraph No. 44). SFAS 87 then goes on to describe a range of interest rates that can be looked at to determine the rate that could be used to settle obligations. [SFAS 106], which governs the accounting of OPEBs, is to the same effect.

In accordance with this guidance, PP&L's proposed discount rate was determined based on a detailed analysis of a variety of factors. The Company's assumed rate is completely consistent with the current market rates at which pension obligations could be settled. In fact, Mr. Catlin's recommendation notwithstanding, record evidence shows that PP&L's assumed rate of 7.5 percent may be too high (PP&L St. 14-R, p. 3).[31]

Second, Mr. Catlin's reliance on PAWC's recent decision to increase its discount rate to 8.75% is misplaced. As noted above, SFAS 87 and SFAS 106 plainly contemplate a range of appropriate rates to be determined based upon the specific circumstances of each company. PP&L's proposed 7.5% rate falls well within the range of rates currently used by different companies (PP&L St. 14-R, p. 4). PAWC's discount rate is not

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[31] As explained by Mr. Beers, a variety of factors support the conclusion that pension obligations likely can be settled at rates 25 to 50 basis points below long-term government yields. Such yields equalled 7.9% as of January 1, 1995. However, as noted by the OCA's own rate of return witness, those yields had declined by approximately 50 basis points as of mid-March (PP&L St. 14-R, p. 3).

dispositive in this proceeding, and Mr. Catlin's argument to the contrary should be accorded no weight.

In sum, PP&L's proposed discount rate is reasonable and fully supported by record evidence. Mr. Catlin's recommended adjustment therefore should be rejected.

3. Post-Retirement Benefits (SFAS 106)

The Company proposes to recover a total of $27,654,00 for costs associated with SFAS 106.[32] PP&L's total includes: (1) $25,857,000 in current SFAS 106 costs; and (2) $31,095,000 of deferred SFAS 106 costs amortized over 17.3 years,[33] or an annual amount of $1,797,000 (PP&L Ex. Future 1 - Revised, Sch. D-6) or $1,555,000 on a PUC jurisdictional basis. Both the OTS and the OCA challenge PP&L's claim for deferred SFAS 106 costs as impermissible "retroactive ratemaking," relying on the Commonwealth Court's decision in Popowsky v. Pa. P.U.C., 164 Pa. Cmwlth. 338, 642 A.2d 648 (1994)("PP&L") (OCA St. 4, p. 10; OTS

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[32] As of January 1, 1993, SFAS 106 required all companies subject to GAAP, including PP&L, to use an accrual method of accounting rather than a cash method of accounting for post-retirement benefits other than pensions ("OPEBs"). SFAS 106 therefore substantially increased the level of OPEBs reflected in PP&L's financial statements and resulted in significant transition costs (PP&L St. 3, p. 18).

[33] This 17.3-year amortization period reflects the remainder of the transition period allowed by SFAS 106.

St. 6, p. 18).[34] For the reasons set forth below, these adjustments are without merit and should be rejected.

a. PP&L's Claim For Deferred SFAS 106 Costs Does Not Violate The General Rule Against Retroactive Or Single-Issue Ratemaking

Public utilities are generally prohibited from recovering past costs through future rates. However, there is a well-recognized exception to that rule for extraordinary and non-recurring expenses, which may be recovered in rates through an amortization allowance. For example, in Pike County Light & Power Co. v. Pa. P.U.C., 87 Pa. Cmwlth. 451, 487 A.2d 118 (1985), the Commonwealth Court held that the Commission did not engage in unlawful retroactive ratemaking when, in a base rate proceeding, it reduced a utility's tax expense by amortizing prior period tax losses. The Court explained the general rule against retroactive ratemaking as follows:

> The Commission clearly may not establish rates which are calculated to retroactively recover surpluses or refund deficits created by inaccuracies in its prior rate authorizations. However, it may take into account extraordinary losses or gains occurring in the past by amortizing them over a period of years. See e.g., Pennsylvania Public Utility Commission v. Duquesne Light Co., 57 Pa. P.U.C. 1 (1983) (deferred taxes); Pennsylvania Public Utility Commission v. West Penn Power Co., 54 Pa. P.U.C. 602 (1981) (tax deficiencies); Pennsylvania Public Utility Commission v. National Fuel Gas Distribution Corp., 54 Pa. P.U.C. 401 (1980) (tax refunds).

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[34] As in the case of his proposed disallowance of pension costs, OCA witness Catlin again contends that the Company has utilized an unreasonably conservative discount rate in calculating its SFAS 106 costs.

In the instant case, PP&L's claimed SFAS 106 deferrals do not reflect surpluses or deficits created by a prior inaccurate rate authorization. The total costs to be accrued under SFAS 106 are identical to the total costs to be paid under a cash-based accounting methodology. The change to SFAS 106 only altered the timing of PP&L's recovery of OPEBs; it did not change the total amount of the Company's liability (PP&L St. 3-R, pp. 7-8). The Company's claimed SFAS 106 deferrals therefore do not violate the general rule against retroactive ratemaking.

Even if one were to assume that PP&L's claimed costs fall within the ambit of this general rule, the Commission and the Courts recognize a well-established exception for extraordinary and non-recurring expenses, provided that such costs are claimed in a base rate proceeding.[35/]

The record evidence amply demonstrates that PP&L's claimed SFAS 106 costs are extraordinary and non-recurring. The adoption of SFAS 106 was an extraordinary, one-time event clearly meeting

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[35/] See e.g., Pa. P.U.C. v. Columbia Gas of Pa., Inc., 74 Pa. P.U.C. 242 (1990) (allowing amortization of cost of Commission-mandated audit of utility operations between base rate cases); Pa. P.U.C. v. Pennsylvania-American Water Co., 68 Pa. P.U.C. 343, 362 (1988) (allowing amortization of initial costs incurred to comply with Pennsylvania One Call System for utilities); Pa. P.U.C. v. National Fuel Gas Dist. Corp., 67 Pa. P.U.C. 264 (1988) (approving amortization of costs incurred for new programs to assist low-income customers with their utility bills); Pa. P.U.C. v. Bell Tel. Co. of Pa., Docket No. R-80061235 (April 24, 1981) (approving amortization of storm damage expenses and costs of implementing new tariffs); Pa. P.U.C. v. PECO-Gas Div., 33 PUR 4th 319 (1980) (allowing amortization of cost to install leased computer).

the exception to the general rule against retroactive ratemaking. Indeed, the Commonwealth Court has determined that transition costs associated with SFAS 106 are properly viewed as extraordinary and non-recurring. Popowsky v. Pa. P.U.C., 164 Pa. Cmwlth. 600, 608, 643 A.2d 1146, 1150 (1994)("PAWC") (finding that the SFAS 106 transition obligation cost "arises from an extraordinary and non-recurring one time event -- the change from cash to accrual accounting -- and the allowance of the recovery of that obligation amortized over a period of twenty years is not retroactive ratemaking").

As noted above, the OTS' and OCA's retroactive ratemaking argument rests solely on the Commonwealth Court's decision in PP&L, and therefore must stand or fall on that basis. Their argument should be rejected, however, because they have misconstrued the Court's decision. On December 4, 1992, PP&L filed a petition with the Commission, outside of a base rate case, requesting permission to defer and recover through rates all prudently incurred OPEB costs recognized beginning January 1, 1993, in accordance with SFAS 106. By Order dated May 6, 1993, the Commission approved PP&L's petition. As explained by Mr. Bernini (PP&L St. 3, p. 18):

> The Commission's approval granted PP&L permission to defer and record, as a regulatory asset, the incremental amount by which the accrued cost for OPEBs under SFAS 106 (including amortization of the Transition Obligation) exceeds the amount actually paid for such benefits during the deferral period. The deferral period was from the date of SFAS 106 adoption (January 1, 1993) until

> the effective date of base rates which reflect recognition of SFAS 106 compliance costs, but, in any event, no later than January 1, 1998. The Order further provided that, in a future rate case, the Company would be permitted to include in base rates an amortization of the recorded asset over a period not to exceed twenty years from the date of adoption of SFAS 106.

On May 26, 1994, the Commonwealth Court reversed the Commission's May 6, 1993 Order. PP&L, supra. Both PP&L and the Commission have filed Petitions for Allowance of Appeal asking the Supreme Court to review the Commonwealth Court's decision.

The Commission Order reversed in PP&L was issued between base rate cases and authorized PP&L to defer and recover past SFAS 106 costs in its next base rate proceeding. In determining that the Commission's order constituted retroactive ratemaking, the Court explained that "PP&L could have recovered [SFAS 106] costs had it filed a rate case rather than a request for declaratory order." PP&L, 642 A.2d at 652. The Court's decision therefore rested on its determination that the Commission inappropriately attempted to permit the recovery of past costs outside of a base rate case.

This conclusion is further supported by the Commonwealth Court's decision in PAWC, supra, which involved a claim for SFAS 106 transition costs. In PAWC, the company requested and received Commission authority to recover past SFAS 106 transition costs in the context of a base rate proceeding. In affirming the Commission's Order, the Court rejected arguments by the OCA that the recovery of such costs violates the general rule against retroactive ratemaking, and determined that the company's claimed costs were both extraordinary and non-recurring and properly recoverable in a base rate case. PAWC, 164 Pa. Cmwlth. at 608, 643 A.2d at 1150.

Consistent with PAWC, the Company's claim for deferred SFAS 106 costs should be allowed. As in PAWC, PP&L is requesting recovery of SFAS 106 costs in a base rate proceeding. Thus, none of the dispositive concerns raised by the Court in PP&L are present in this case.

b. PP&L's Proposed Discount Rate Is Appropriate And Should Be Approved

Mr. Catlin argues that the Company has overestimated its SFAS 106 costs because it has utilized any overly conservative discount rate of 7.5% in calculating its claim (OCA St. 6, pp. 14-16). This argument is identical to the one Mr. Catlin offers in connection with PP&L's claimed pension expense. Mr. Catlin's proposal therefore should be rejected for the same reasons previously discussed in Section V.A.2.b, *supra*.

4. SFAS 112 Costs

PP&L's operating expense claim includes $996,000 for the accrual of costs attributable to SFAS 112. SFAS 112 addresses the appropriate accounting treatment of long-term disability and other benefits provided to disabled employees and the families of deceased employees prior to retirement. In accordance with SFAS 112, the Company's claim reflects an accrual for the anticipated increase in future liability for such long-term benefits.

OCA witness Catlin asserts that the Company's claim should be disallowed in its entirety because there is no reason to change the ratemaking treatment of such long-term benefits from a cash to an accrual basis (OCA St. 6, p. 19; OCA St. 6A, p. 5). His proposed adjustment would reduce test year operating and maintenance expenses by $684,000 on a total Company basis, and by $592,000 on a Pennsylvania jurisdictional basis (OCA St. 6, pp. 19-20).

As a general matter, the Company keeps its books and records, and its rates are set, on an accrual, not a cash, basis. The adoption of SFAS 112 is therefore fully consistent with GAAP and well-established ratemaking principles. As explained by Mr. Berish, PP&L's claim also is wholly consistent with the treatment of similar types of employee benefits expenses (PP&L St. 2-R, pp. 16-17):

> From a ratemaking standpoint, the same factors (e.g., intergenerational equity, rate stability) that support the use of SFAS 87 for pension expense and SFAS 106 for other post-retirement benefits also apply to similar benefit costs for disabled and deceased employees (i.e., long-term disability, survivor income protection) which must now be accrued under SFAS 112. In my opinion, the fact that the Company does not plan to establish a separate funding vehicle for this liability provides no basis for disallowing its claim, particularly in light of the magnitude of the dollars in question and the potential costs of

establishing and operating a fund ear-marked for that purpose.

Mr. Catlin offered no reasoned basis for continuing cash basis accounting for this one item of employee benefits expense and his recommended adjustment should, therefore, be rejected.

5. SSES Early Window Costs

Early window deferrals are those operating and maintenance expenses incurred between the date a new generating unit enters commercial operation and the date it is recognized in rates. Such deferrals are, in effect, accounting mechanisms which permit a utility to synchronize the costs and benefits of bringing a new plant into operation, while ensuring that the timing of a plant's commercial operation is not affected by ratemaking considerations (PP&L St. 3-R, p. 11).

PP&L's final total amount for "early window" deferrals related to SSES 1 and 2 is $39,215,000, which the Company has proposed to amortize over a ten-year period, or $3,922,000 per year (PP&L St. 3-R, p. 13). The OTS and the OCA propose the disallowance of PP&L's claimed early window costs because, in their view: (1) the Company's claim is not timely; and (2) the Company's claim violates the general prohibition against retroactive ratemaking (OTS St. 4, p. 17; OCA St. 6, p. 28). For the reasons discussed below, these arguments lack merit and should be rejected.

a. PP&L's Claim Is Timely And Thus Should Be Allowed

During the early 1980s, the Commission specifically allowed PP&L to defer its SSES 1 and 2 "early window" costs and to claim these costs in a future rate proceeding. Even though this is PP&L's first base rate proceeding since 1985, the OTS and OCA nonetheless challenge the timeliness of PP&L's claim. These arguments fail to withstand careful scrutiny.

First, the OTS and the OCA assert that PP&L should have sought recovery of these costs earlier and that its claim is simply too late (OTS St. 4, p. 17; OCA St. 6, p. 28). However, the Commission's prior Orders authorizing SSES 1 and 2 early window deferrals do not establish any time limit on PP&L's ability to recover these costs. Those Orders state, inter alia:

> The issuance of this Order does not in any manner whatsoever determine the used and useful nature of Susquehanna Unit 1. Also, it is not a determination by the Commission that the costs involved were prudently incurred, that the energy savings properly recorded or that the Company may recover deferred costs or retain deferred energy savings. Recovery of these costs will be subject to subsequent Commission audit and final disposition in a rate case proceeding.

Petition of Pennsylvania Power & Light Co., Docket No. P-820367, 1982 Pa. PUC LEXIS 75, *17-18 (Order entered July 29, 1982), and

> The issuance of this Order does not in any manner whatsoever determine the used or useful nature of Susquehanna Unit 2. Also, it not a determination by the Commission that the costs involved were prudently incurred, that the energy

> savings were properly recorded or that the Company may recover deferred costs or retain deferred energy savings. Any claim for recovery of these costs will be subject to subsequent Commission audit and final disposition in any appropriate proceeding filed subsequent to the entry of a Final Order in the Susquehanna Unit 2 rate case proceeding. In said subsequent proceeding PP&L shall file actual cost data and the full accounting detail in support thereof and notice and opportunity to be heard will be provided. The question of whether the Company may recover the deferred costs, the reasonableness of these costs, and the merits of a cost recovery mechanism will be determined by the Commission in said subsequent proceeding.

Petition of Pennsylvania Power & Light Co., Docket No. P-830461, (Order entered November 9, 1983).

Furthermore, the opposing parties' "timeliness" argument is somewhat puzzling, since its effect would be to encourage more frequent base rate cases. As explained by Mr. Bernini, PP&L sought to delay its next base rate case until the 1994-95 time frame in an attempt to maintain rate stability (PP&L St. 3-R, p. 12). PP&L's success in these efforts has clearly benefitted customers. Such efforts should be encouraged, not penalized.

Second, both the OTS and the OCA argue that PP&L's claim for SSES 1 costs is barred because it should have been asserted in PP&L's Unit 2 Case (OTS St. 4, p. 17; OCA St. 6, p. 29). However, in the Unit 2 Case, the Company requested a very substantial rate increase of $330 million, or approximately 23% (PP&L St. 3-R, p. 11). In an effort to minimize the requested increase and its impact on customers, the Company did not claim deferred SSES 1 early window costs at that time (PP&L St. 3-R, pp. 11-12). The Company should now not be punished for this reasonable action.[36]

PP&L has properly claimed its deferred SSES 1 and 2 early window costs in this proceeding. The Company's claim is fully consistent with the Commission's prior authorizations and therefore should be allowed.

b. PP&L's Claim Does Not Violate The General Rule Against Retroactive Ratemaking

The OTS also argues that PP&L's claim for SSES 1 and 2 early window deferrals violates the general rule against retroactive ratemaking. This argument must fail for several reasons.

First, as discussed in Section V.3 supra, the Commission has established an exception to the general rule against retroactive ratemaking which allows for the recovery of "extraordinary or nonrecurring" expenses. See, e.g., Pike County Light & Power Co. v. Pa. P.U.C., supra (the Commission did not engage in unlawful retroactive ratemaking when, in a base rate proceeding, it reduced a utility's tax expense by amortizing prior period tax losses). Indeed, the Commission has exercised its authority to permit the amortization of past costs in many base rate proceedings.

[36] In addition, it is important to note that PP&L's alleged "delay" in filing its early window expense claim has not increased the amount of such claim. The Company's claimed costs do not include any carrying charges accrued during the deferral period.

PP&L's claimed SSES 1 and 2 early window deferrals clearly fall within this exception. The construction of a new nuclear power plant is obviously an extraordinary and non-recurring event, and the Commission has specifically held that the related deferral costs are recoverable. Pa. P.U.C. v. Philadelphia Electric Co., Docket No. R-891364 (May 16, 1990) (Order, p. 212) ("PECO") ("'Early window' costs are extraordinary for the reason that the initial commercial operation of a large nuclear plant, costing billions of dollars, occurs infrequently, and clearly represents a non-recurring event"). Therefore, as extraordinary and non-recurring expenses, PP&L's claimed SSES 1 and 2 early window costs do not violate the general rule against retroactive ratemaking.

Second, and as noted above, the Commission previously allowed recovery of deferred early window costs in PECO. The costs claimed in PECO were identical in nature to those being claimed by the Company in the instant case. The Commission's Order in PECO therefore should control this proceeding. Despite its clear relevance, the OCA attempts to distinguish PECO on the ground that the Commission found in PECO that disallowance of deferred costs would seriously impact PECO's financial condition (OCA St. 6, p. 29). This argument is without merit.

The unrebutted record evidence plainly demonstrates that disallowance of PP&L's claimed early window costs would have a severe impact on the Company's earnings. Specifically, a disallowance of such costs would force the Company to write-off the entire $39 million in 1995. The effect of this write-off would be approximately $0.25/share, as compared to total 1994 earnings of $1.41/share (PP&L St. 3-R, p. 13). If the effect of this write-off were calculated in 1985, earnings would be reduced by $0.53/share, as compared to 1985 earnings of $2.68/share (PP&L St. 3-R, p. 14). The impact of such a write-off is clearly significant under any reasonable standard.

6. SSES Refueling Outage Expense

PP&L's final total O&M amount for SSES refueling outage costs, on a Pennsylvania jurisdictional basis, is $17,581,000 (PP&L St. 2-R, p. 9) or $13,813,000 on a PUC jurisdictional basis. This level of expense was derived by amortizing each unit's refueling outage costs over the period between refueling outages (PP&L St. 2-R, p. 8). This "matching" methodology is consistent with GAAP and ensures that expenses incurred during refueling outages are recognized during the subsequent operating periods when the benefits from such expenses are realized (Id.). The Company's claimed future test year expenses include the completion of the amortization of Unit 1, Reload 7, the initiation of Unit 1, Reload 8 (scheduled to last from March 25, through May 22, 1995), and the amortization of Unit 2, Reload 6 (PP&L St. 2-R, pp. 8-9; OCA St. 6, p. 30).

OCA witness Catlin proposes to adjust PP&L's claimed amortization of refueling outage costs to reflect an annualized level of expense based on the costs of the "most recent" refueling outage at each plant, i.e., Unit 1, Reload 8 and Unit 2, Reload 7 (OCA St. 6, p. 30). Thus, Mr. Catlin's recommendation would: (1) disallow Unit 1, Reload 7 costs since they are not attributable to the most recent outage at Unit 1; (2) recognize $11,322,000 of Unit 1, Reload 8 costs; and (3) recognize $9,664,000 of Unit 2, Reload 7 costs since they will be attributable to the then-most-recent refueling outage. Based on these adjustments, Mr. Catlin recommends an annual refueling outage allowance of $16,470,000, or $1,111,000 ($873,000 on a PUC jurisdictional basis) less than the total final amount (PP&L St. 2-R, p. 9). Mr. Catlin's adjustment is without merit and should be rejected for several reasons.

Mr. Catlin contends that his adjustment is appropriate because it excludes Unit 2, Reload 6, whose cost, duration and amortization period were allegedly "abnormal" (OCA St. 6, p. 31). The record evidence demonstrates that Mr. Catlin's concerns regarding Unit 2, Reload 6 are unfounded. In fact, as Mr. Berish explained (PP&L St. 2-R, p. 10), the cost of Unit 2, Reload 6 is almost identical to the projected cost of Unit 1, Reload 8 (PP&L Ex. MJB-13). Mr. Catlin has not challenged the estimated cost of Unit 1, Reload 8 and, in fact, has utilized it in developing his recommendation. The costs of Unit 2, Reload 6 therefore should be found to be reasonable as well (PP&L St 2-R, p. 9).[37/]

In sum, Mr. Catlin's proposed adjustment is arbitrary and unsupported and should, therefore, be rejected.

7. Environmental Remediation Costs

The Company's annual expense level for environmental remediation costs is $5,400,000 or $4,400,000 on a PUC jurisdictional basis (PP&L St. 2-R, p. 2). Both the OTS and the OCA initially challenged PP&L's claim, contending that recent, actual expenditures do not support the claimed level of expense (OTS St. 4, p. 18; OCA St. 6, p. 31). More specifically, the OTS recommended a reduction of $1,304,000 to PP&L's jurisdictional claim based on an annualization of the highest monthly expense amount incurred during the historic test year (OTS St. 4, p. 18). The OCA, in turn, proposed a $3,017,000 reduction based on the actual costs incurred during the 12-month period ended February 1995 (OCA St. 6, p. 32). As became apparent during the rebuttal phase of this case, however, it is clear that historic

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[37/] In his surrebuttal testimony, Mr. Catlin asserted that the costs of refueling at Unit 1 are normally higher than those at Unit 2 (OCA St. 6A, p. 2). In support of his argument, Mr. Catlin submitted a table providing information for Reloads 5 through 8 at Unit 1 and Reloads 4 through 7 at Unit 2 (OCA St. 6A, p. 3). An outage-by-outage comparison of the costs associated with <u>all</u> refueling events for each unit, however, reveals that Unit 1 was more costly than Unit 2 in three instances, and that the converse was true in the remaining three instances (Tr. 2046).

expenditure levels are not an accurate indication of PP&L's future costs.

On April 27, 1995, after extensive negotiations, PP&L signed an agreement with the Pennsylvania Department of Environmental Resources ("DER") which requires the Company to investigate and, if necessary, clean up 134 potentially contaminated sites (PP&L St. 2-R, pp. 2-3). PP&L adopted this site remediation strategy in response to a Commission management audit finding which advised PP&L to ensure that "appropriate and effective actions are taken to prevent or minimize future Superfund liabilities" (PP&L Ex. MJB-10). As explained by Mr. Berish, PP&L's experienced costs were low, in part, because the Company was awaiting execution of the agreement with DER (PP&L St. 2-R, p. 3).

Second, the Company's remediation costs through March 1995 also were low because of winter weather conditions. A substantial portion of the remediation activities include soil sampling and removal. From a practical viewpoint, it is far more efficient and cost-effective to undertake these activities beginning in the Spring when the ground has thawed (PP&L St. 2-R, p. 4).

Third, the Company has incurred additional environmental remediation expenses in the past several months. As explained by Mr. Berish, PP&L has provided information regarding these additional costs through April 1995 (Id.).

Based on the Company's rebuttal evidence and the execution of the DER agreement, Mr. Catlin withdrew his proposed adjustment (OCA St. 6A, p. 2). Mr. Weakley reduced his proposed adjustment to $326,000, but offered no explanation to support the development of this new figure (OTS St. SR-4, p. 5). As explained above, the Company's claim is fully supported by the record evidence. There is absolutely no basis for the OTS's adjustment, and the Company's claim therefore should be allowed.

8. Uncollectible Accounts Expense

PP&L's final PUC jurisdictional claim for uncollectible accounts expense includes two components: (1) $16,932,000 for normal uncollectible accounts expense; and (2) $942,625 for costs associated with PP&L's customer assistance program, which is referred to as the OnTrack Payment Program ("OTPP") (PP&L St. 2-R, p. 6).

OTS witness Weakley recommends a reduction in the Company's claim in the amount of: (1) $1,234,000, on a PUC jurisdictional basis, for normal uncollectible accounts expense; and (2) $140,000, on a PUC jurisdictional basis, for the OTPP (OTS St. 4, pp. 25, 30). Mr. Weakley's proposed adjustments are without merit and should be rejected.

Mr. Weakley's $1,234,000 reduction to normal uncollectibles results from his assertion that PP&L's claim should reflect its projected actual write-offs rather than the provision for uncollectibles.[38] The Company has demonstrated, however, that it is more appropriate to use the provision for uncollectibles of $16,932,000 because it is consistent with the same future test year sales levels utilized by PP&L to determine pro forma present rate revenues. In contrast, the lower write-off amount advocated by Mr. Weakley is associated with sales and recorded revenues experienced in prior periods (PP&L St. 2-R, p. 6). The Company's proposal therefore affords a better matching of revenues and expenses and should be approved on that basis alone.

Even if the OTS's write-off methodology were appropriate, its proposed adjustment should still be rejected because the projected future test year write-offs of $15,566,499 are abnormally low in comparison to the Company's historic experience (Id.). If Mr. Weakley had used a three-year average of actual

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[38] Mr. Berish explained the difference between a provision for uncollectibles and an actual write-off as follows (PP&L St. 2-R, pp. 5-6):

> Under well-established accounting practices, revenue from electric sales is recorded for book purposes when the customer uses the energy and a bill is rendered. In other words, utilities do not record the revenue when the cash is actually collected from customers, and, indeed, the bill may actually be paid months, or even years, after the revenue is recorded. However, to reflect the fact that some of the recorded revenue will never be collected, utilities book to expense an amount, referred to as a provision for uncollectibles, which attempts to identify how much of the recorded revenue eventually will be written off. The reason for doing this is to avoid overstating or understating earnings. In essence, this charge to expense provides a "matching" with the recorded revenues.

write-offs to better reflect the Company's experienced costs, his allowance would have been $17.1 million, or $0.2 million higher than PP&L's claimed expense (PP&L St. 2-R, p. 7).[39]

Finally and perhaps most importantly, PP&L followed an extremely conservative approach in this case and elected not to reflect in its filing the incremental uncollectible accounts expense related to its requested rate increase. This cost equals approximately $1.6 million, which would completely offset Mr. Weakley's proposed disallowance (Id.).

In sum, there is no support for Mr. Weakley's proposed $1,234,000 reduction to PP&L's claim for normal uncollectible accounts expense. Such disallowance therefore should be rejected.

Mr. Weakley next contends that PP&L has overstated the uncollectible accounts expense element of the OTPP because it failed to reflect potential funding from the Low Income Home Energy Assistance Program ("LIHEAP") (OTS St. 4, p. 30). More

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[39] In other cases, the OTS has often proposed a three-year average for uncollectible accounts expense. See e.g., Pa. P.U.C. v. UGI Utilities, Inc. - Electric Division, Docket No. R-00932862, 1994 Pa. PUC LEXIS 137, *28-29 (Order entered July 27, 1994)("OTS proposed to base the Company's claim for uncollectible accounts expense on a three-year average ratio of uncollectible accounts expense to revenues"); Pa. P.U.C. v. Nat'l Fuel Gas Dist. Corp., 73 Pa. P.U.C. 552, 573 (OTS proposed calculation of uncollectible accounts expense "by matching uncollectible accounts, net of recovery, against book revenues for a three-year period and expressed as a percentage of revenues"); Pa. P.U.C. v. Nat'l Fuel Gas Dist. Corp., 72 Pa. P.U.C. 1, 36 (OTS recommended using three-year average of net write-offs).

specifically, the OTS proposes a decrease of $140,000 to the level of uncollectible accounts expense of $710,000 that PP&L included for its OTPP. The OTS's recommended adjustment is intended to recognize amounts received under LIHEAP on behalf of customers participating in the OTPP.

The OTS correctly observed that the $710,000 uncollectible accounts expense component does not reflect LIHEAP cash benefits or Crisis benefits (PP&L St. 11-R, p. 3). When the $710,000 calculation was performed, PP&L had little or no information as to what level of LIHEAP or Crisis dollars would be received on behalf of OTPP participants or how many OTPP participants would actually receive LIHEAP or Crisis grants (Id.).

PP&L takes issue, however, with the computation method used by the OTS (see PP&L St. 11-R, pp. 2-4), and has determined that an adjustment of $130,000 would be more appropriate, if an adjustment is to be made (PP&L St. 11-R, p. 4). However, the main dispute between the OTS and PP&L relates to whether an adjustment should be made at all. The OTS adjustment fails to give any weight to the fact that Federal funding for LIHEAP has been substantially reduced in the past and probably is going to be reduced further or eliminated in the current round of Federal budget tightening (Tr. 1980-81).

The Commission has recognized this concern in recent orders involving interim reductions in purchased gas cost recovery rates by gas utilities. Indeed, Commissioner Rolka expressly stated that increased scrutiny of future projections in Section 1307(f) gas cost proceedings "will be increasingly important in view of the potential for significantly reduced funds available from the Low Income Home Energy Assistance Program." Pa. P.U.C. v. Pennsylvania Gas & Water Co., Docket No. R-00953381 (Statement of Commissioner Rolka dated May 11, 1995).

PP&L also explained that Federal funding for LIHEAP has dropped from $2.1 billion in fiscal year 1986 to $1.3 billion in fiscal year 1995, a decrease of 38% (PP&L St. 11-R, p. 5). Pennsylvania's LIHEAP allocation for this same period has fallen from $141 million to $100 million, a decline of 29% (Id.). Moreover, the U.S. House of Representatives, in House Bill 1558, approved on March 16, 1995, voted to eliminate completely LIHEAP funding in fiscal year 1996. While the U.S. Senate is considering the issue and may attempt to restore some level of LIHEAP funding, it is very possible that LIHEAP's funding will be reduced significantly. Under these circumstances, the OTS's proposed adjustment should be rejected.

9. Rate Case Expense

The Company has reflected $1,491,000 for rate case expense in test year O&M expense (PP&L Ex. Future 1 - Revised, Sch. D-7). PP&L proposes to normalize this expense over a two-year period, thereby resulting in its final annualized claim of $746,000 (Id.). Based on a review of PP&L base rate cases over a twenty-year period, OTS witness Weakley recommended a four-year normalization period (OTS St. 4, p. 22). Similarly, DOD witness Prisco advocated use of a three-year period (DOD St. 1, p. 6). These proposals should be rejected.

As explained by Mr. Bernini, the conditions that enabled PP&L to delay the filing of the instant base rate case are unlikely to recur in the near future (PP&L St. 3-R, pp. 5-6). For that reason, it is inappropriate to reflect this abnormally long stay-out period in evaluating PP&L's rate case expense claim in this proceeding. Indeed, if this extended filing interval of 125 months is excluded from the data reviewed by Mr. Weakley, the Company's average rate case filing period is 2.3 years (Id.). PP&L's proposed two-year period is therefore reasonable and should be allowed.

Furthermore, the Company may be forced to file its next base rate case in less than two years. As Mr. Bernini explained (PP&L St. 3-R, p. 6), the disposition of the instant proceeding will obviously affect the date of that filing:

> In this filing, the Company has requested levelization of Susquehanna Modified Sinking Fund depreciation in base rates and the recovery of the costs associated with the return of the JCP&L capacity and energy sales agreement through the ECR. If items such as these are disallowed, they will expose the Company to very substantial costs that will not be reflected in rates. If these claims are approved, the Company will be willing to accept a longer normalization period. Otherwise, the two-year period proposed by the Company [is] the maximum reasonable period, and probably is too long.

PP&L's proposed two-year amortization period is fully supported by substantial record evidence. The OTS' and the DOD's recommended adjustments therefore should be rejected.

10. Customer and Community Needs Programs

In this proceeding, PP&L has proposed to undertake several new customer and community needs programs (PP&L St. 11, p. 14). These programs include the following:

- Build-A-Neighborhood Program;
- Affordable Housing Program;
- Small Business Program;
- Keep Warm Plan;
- Payment Protection Plan;
- Winter Emergency Plan;
- Operating HELP Contribution Enhancement Program; and
- CARES Extension Pilot Program.

The foregoing programs were explained in detail by Mr. Stathos at pages 17-27 of PP&L Statement 11. In general, the purpose of these programs is to promote the efficient usage of electricity, to promote economic development and to provide social services support in the Company's service territory. PP&L believes that such programs are in the best interests of the Company and its customers and are an important part of its overall corporate mission (PP&L St. 11, p. 15).

The total annual projected cost of these programs is $6.7 million, which break downs as follows: (1) conservation, efficiency, load management and rate incentive programs ($3.5 million); and (2) other program costs, including charitable contributions, neighborhood improvements, closing and real estate costs, grants for small businesses ($3.2 million) (PP&L St. 11, pp. 30-31; PP&L St. No. 11-R, pp. 11-12). PP&L seeks rate recovery only for the first category of expenses; the second category will be funded entirely by shareholders (PP&L St. 11, p. 30; PP&L St. 11-R, p. 11).

a. The OTS's Proposed Adjustment To Eliminate The Costs Of Certain Proposed Customer And <u>Community Needs Programs Should Be Rejected</u>

The OTS recommends the disallowance of $2,500,000, or approximately 70% of the $3,530,000 that PP&L has proposed to include in expenses to be recovered in this proceeding (OTS St. 4, pp. 35-41). This represents the total disallowance of the costs related to three specific programs, namely the Build-A-Neighborhood, Affordable Housing and Small Business Programs (OTS St. 4, pp. 34-35). The OTS objects to the inclusion of the costs of these programs for six different reasons:

- There are significant "hidden" costs associated with each of the programs;
- The programs are not driven by specific Commission-approved regulatory goals;
- There is no discernible benefit to ratepayers;
- These programs are being funded by forced contributions;

- These programs are not compatible with the competitive environment evolving in the electric utility industry; and
- Counsel for the OTS advises that ratepayer funding of these programs is "illegal".

For the reasons set forth below, the OTS's objections provide no basis for rejecting the Company's claim.

(1) The Proposed Programs Do Not Include And Will Not Cause Any "Hidden" Costs

The OTS's claim of "hidden" costs is incorrect for two reasons. First, PP&L has not hired, and does not plan to hire, any new employees to implement the new customer and community programs (PP&L St. 11-R, p. 6). Instead, the Company will rely on existing employees who are already administering similar programs (e.g., WRAP, Operation HELP, CARES, OnTrack), to implement the new social initiatives. Id. Moreover, PP&L will work extensively with existing community organizations and coalitions to administer the programs (PP&L St. 11-R, p. 7). There are no "hidden costs."

(2) PP&L's Proposed Programs Are Consistent With The Commission's Actions Urging Utilities To Provide Innovative Programs And Services And The Commission's And The Commonwealth's Encouragement And Support Of Economic And Community Development Activities

The OTS alleges that the costs of the programs should not be allowed because they are not driven by specific, Commission-approved regulatory goals (OTS St. 4, p. 36). The OTS's allegations are simply incorrect. The programs which PP&L seeks to include in rates will promote conservation, load management and economic development. These programs are simply an expansion of existing Commission-approved programs. Indeed, each of these activities -- conservation, load management and economic development -- has been specifically encouraged by the legislature and/or the Commission. See, e.g., 52 Pa. Code §58.2 et seq. (PUC support for implementation and rate recovery of low income weatherization and conservation programs); 52 Pa. Code §58.4 (PUC policy statement supporting customers assistance programs designed to help payment troubled customers pay their utility bills); Investigation Into Demand Side Management By Electric Utilities, Docket No. I-9000005 (Order entered December 13, 1993) (PUC support for demand side management and conservation programs).

In addition, the Commission has supported a wide variety of economic development initiatives in the past. For instance, the Commission has approved a series of economic development initiatives filings by PP&L aimed at retaining jobs and investment and attracting new jobs and investment in communities located in its service territory. Pa. P.U.C. v. Pennsylvania Power & Light Co., Docket No. R-832542 (Order entered February 28, 1984); Pa. P.U.C. v. Pennsylvania Power & Light Co., Docket No. R-850251C001 (Order entered July 8, 1987); Pa. P.U.C. v. Pennsylvania Power & Light Co. Docket No. R-870060C001 (Order entered September 21, 1987); Pa. P.U.C. v. Pennsylvania Power & Light Co., Docket No. R-00922363 (Order entered July 23, 1992). The Commission also has approved economic development offerings of numerous other utilities. See, e.g., Pa. P.U.C. v. Pennsylvania Power Co., Docket No. R-943238 (Order entered December 2, 1994).

(3) PP&L's Proposed Programs Will Benefit Ratepayers

The OTS also asserts that it is "unknown" whether the programs will result in benefits to PP&L's ratepayers (OTS St. 4, pp. 37-39). The OTS's concern is misplaced and should be rejected. As Mr. Stathos explained, the total annual cost of the Build-A-Neighborhood, Affordable Housing and Small Business Programs is $5.25 million, of which PP&L is seeking cost recovery for only $2.5 million (PP&L St. 11-R, p. 9). The $2.5 million will be used for services such as:

- Weatherization
- Energy conservation education
- Heating system replacement or repair

- Energy efficient equipment improvements
- Rate Incentive Costs

(PP&L St. 11-R, p. 9; PP&L St. 11, p. 31).

In its LIURP regulations, the Commission has clearly recognized the benefits to all customers of promoting weatherization, energy conservation education, and energy efficiency. 52 Pa. Code §§ 58.1 to 58.18. These activities reduce energy usage and have a positive impact on customers' ability to pay their electric bills (PP&L St. 11-R, pp. 9-10). This, in turn, will benefit all customers by reducing peak demand and uncollectible accounts expense. Reducing energy usage for low-income customers and improving bill-payment habits has benefits for all (PP&L St. 11-R, p. 11).

In addition, to the extent that urban neighborhoods can be strengthened and revitalized by the kinds of expenditures and activities proposed, there may be a favorable impact on energy sales or, at least some prevention against the deterioration of existing energy sales. Thus, all customers may benefit as fixed costs are spread over a larger sales base.

Finally, the Commission should not ignore the social benefits that can accrue to PP&L's customers and the communities in which they live and work as a result of PP&L's programs. In prior cases involving economic development initiatives and rates designed to increase sales volumes, the Commission has recognized these "secondary economic benefits". See, e.g., Pa. P.U.C. v.

National Fuel Gas Distribution Corp., 69 Pa. P.U.C. 379, 382 (1989).

(4) PP&L's Programs Are Not Being Funded By "Forced Contributions"

At page 39 of his direct testimony, OTS witness Weakley alleges that customer funding of these programs would be tantamount to "forced contributions." PP&L is seeking cost recovery only for weatherization services, energy efficiency, load management and rate incentive measures. All other non-energy related services associated with these programs would be funded by the Company's shareholders (PP&L St. 11-R, p. 11). There are no "forced contributions" and the OTS's concerns to the contrary should be disregarded.

(5) PP&L's Programs Are A Vital Part Of Its Success In A More Competitive Electric Utility Environment

The OTS claims that the expansion of "social costs" at this time is not compatible with increased competition evolving in the electric industry (OTS St. 4, p. 40). PP&L disagrees. As the electric utility industry becomes more competitive, PP&L's expanded customer and community needs agenda is an important part of the Company's strategic planning (PP&L St. 11-R, p. 12). In a more competitive environment, PP&L must take steps to ensure that all constituencies in its service territory prosper and grow to the maximum extent possible (Id.).

PP&L's proposed customer and community needs programs are designed to benefit PP&L <u>and</u> its customers by attempting to address, in a modest way, the social issues facing PP&L's customers. These programs will position PP&L favorably with all segments of its customers, <u>including</u> lower income customers located in urban communities. This concrete demonstration of PP&L's commitment to customer and community needs will assist, not hinder, it in a more competitive electric industry (PP&L St. 11-R, pp. 12-13).

(6) <u>PP&L's Proposed Funding Of Customer And Community Needs Programs Is "Legal"</u>

OTS witness Weakley lastly asserts that, in addition to the OTS's other concerns, he has been "advised by counsel that ratepayer funding of these programs is illegal". Although no basis for such legal argument has yet been presented by the OTS, it is clear that, as proposed by PP&L, the inclusion in rates of the types of programs at issue here is "legal" and, in fact, has already been approved by the Commission, as evidenced by the regulations and the other cases cited above.

b. <u>PP&L Has Addressed The Concerns Expressed By The OCA</u>

In his direct testimony, OCA witness Catlin expressed concerns about the lack of an implementation plan for PP&L's new customer and community needs programs. In response, PP&L developed a preliminary implementation plan and timeline. The details of that implementation plan are included in Attachment 1 to PP&L Statement 11-R. The OCA did not question PP&L's implementation plan and presumably has no further objections.

c. The CEO's Concerns And Proposals About PP&L's Customer And Community Needs Programs Must Be Rejected

The CEO expressed various concerns about PP&L's existing and proposed customer and community needs programs, which may be summarized as follows:

- Current and proposed programs are not being made available proportionately across PP&L regions;
- PP&L's commitment to these programs is merely "window dressing" and is being done for public relation benefits;
- Current and proposed conservation programs should be expanded for "baseload" customers;
- Funding for PP&L's proposed programs should be significantly increased over the levels proposed; and
- Funding for the Build-A-Neighborhood and Affordable Housing Programs should be distributed in the form of block grants.

(CEO St. 1, pp. 5-11).

The CEO's concern regarding the distribution of funding of the new programs throughout PP&L's regions, while well-intentioned, should be rejected. As Mr. Stathos explained, customer and community needs simply cannot be adequately addressed by the Company alone, despite its size and presence in the community (PP&L St. 11-R, p. 15). PP&L has attempted to determine the cost of providing meaningful programs that can make at least a modest impact. The Company would, of course, prefer to initially fund the programs uniformly in each of its regions. However, as with other programs, PP&L will certainly consider measures to allocate funding in a more flexible way in the future, once the programs are up and running (PP&L St. 11-R, pp. 15-16).

The CEO's recommendation that current and proposed conservation programs should be expanded for "baseload" customers should also be rejected. Offering conservation services to customers who have neither electric heat nor electric water heating provides little benefit to PP&L and its other customers. In contrast, providing conservation services to customers who heat their homes and/or water with electricity helps to lower electric bills, reduce uncollectible accounts expense and control the growth of peak demand (PP&L St. 11-R, p. 19).

Moreover, the Company already offers services in the form of energy conservation and compact florescent lights to low-use customers through WRAP. In addition, PP&L anticipates installing "GreenPlugs" as part of the WRAP conservation package for baseload customers.[40/] PP&L believes that this level of support is appropriate (PP&L St. 11-R, pp. 19-20).

40/ A GreenPlug is an electronic device that is plugged into an electrical outlet in the home. By controlling voltage levels, it allows appliances to operate more efficiently and reduces energy usage.

The CEO's concern that PP&L's new customer and community programs are merely "window dressing" and are being implemented primarily for public relations reasons should be rejected in the strongest possible terms. PP&L takes serious exception to any implication that the proposed customer and community needs programs are being done only for public relations purposes (PP&L St. 11-R, p. 21). PP&L has a strong and long-standing track record in addressing the special needs of customers and communities and has been among the industry leaders in implementing special programs for customers. Most of the Company's programs (e.g., CARES, Operation HELP, WRAP) have been in existence between 10 to 15 years, have cost PP&L over $30 million during that period and have helped more than 60,000 low-income customers. All of these programs were implemented voluntarily by the Company, and have been continued, expanded, and strengthened over the years.

Regarding the CEO's proposal to significantly increase funding for the proposed programs, PP&L believes that such an undertaking would be inappropriate until such time that evaluation studies have been completed (PP&L St. 11-R, p. 23. At the end of its three-year commitment to the implementation of the programs, PP&L will assess their effectiveness and decide whether or not to modify, expand, or discontinue them. Id.

Finally, the CEO's suggestion that funding for the Build-A-Neighborhood and Affordable Housing Programs be distributed in the form of block grants should be rejected. Until meetings are conducted with community organizations that are likely to be involved in these two programs, PP&L believes that it is premature to suggest a funding mechanism (PP&L St. 11-R, p. 24). The Company is not opposed to the block grant approach, but it needs more information on how to effectively implement such a program with appropriate oversight features. Id.

B. Decommissioning/Dismantlement Costs

1. Nuclear Decommissioning Costs

The Company's claim for operating expenses includes $22.9 million as an annual annuity accrual to fund decommissioning costs for SSES 1 and 2 totalling $804.3 million (at 1993 price levels) (PP&L Ex. Future 1, Sch. D-11). Mr. Bernini calculated the annuity accrual by:

- escalating the decommissioning cost estimate using an annual inflation rate of 4% for each year from 1993 to the end of the license life of SSES;
- subtracting from the escalated decommissioning cost estimate the September 30, 1995 balance of the Company's nuclear decommissioning trust fund (the difference is the sum of money PP&L must accrue by the retirement of SSES 1 and 2); and
- using an after-tax earnings rate of 5.5% to calculate the amount PP&L must add to the trust fund each year to accumulate the sum needed when SSES is retired (PP&L St. 3, pp. 20-21).

The 1993 decommissioning cost estimate was based on the results of a site-specific study for SSES 1 and 2 prepared by

Mr. Thomas S. LaGuardia, President of TLG Services, Inc. TLG and Mr. LaGuardia have extensive experience in planning and managing nuclear decommissioning projects.[41/] The decommissioning study of SSES employs well-accepted methods and analytic techniques, which comply fully with the Nuclear Regulatory Commission's ("NRC") Final Rule entitled "General Requirements for Decommissioning Nuclear Facilities" (53 Fed. Reg. 24018) (June 27, 1988).

Various adjustments to the Company's nuclear decommissioning expense claim have been proposed by opposing party witnesses. Two of the proposed adjustments (elimination of non-radiological costs and the contingency factor) relate to the decommissioning study itself. The remaining three adjustments relate to the way the annuity was calculated, i.e., the appropriate trust fund

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41/ Mr. LaGuardia has had lead roles in decommissioning power reactors at the Elk River (Minnesota) and Shippingport (Pennsylvania) Stations in the United States and Gentilly Unit 1 in Canada. TLG also prepared decommissioning plans, cost estimates and work schedules for the Rancho Seco, Shoreham, Yankee Rowe, Trojan and Big Rock Nuclear Power Stations, which are currently being decommissioned. Under Mr. LaGuardia's direction, TLG has prepared site-specific decommissioning studies for most of the nuclear power plants in the United States (PP&L St. 13, pp. 4-9). Mr. LaGuardia co-authored the "Decommissioning Handbook" for the United States Department of Energy and "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" for the Atomic Industrial Forum, National Environmental Studies Project. In addition, TLG was retained by the Nuclear Regulatory Commission to prepare a study, which Mr. LaGuardia co-authored, entitled "Identification and Evaluation of Facilitation Techniques for Decommissioning Light Water Power Reactors," which evaluated the costs, schedules and environmental impacts of decommissioning large (over 1000 Mw) reactors (PP&L St. 13, pp. 8-9).

earnings rate; whether post-shutdown trust fund earnings should be reflected; and whether a simple amortization rather than an annuity method should be used to calculate the annual decommissioning accrual. The proposed adjustments are discussed individually below.

a. Removal Of Non-Radiological Structures

The OCA's witness, Mr. Dale Bridenbaugh, proposed eliminating the costs of dismantling and removing non-radiological structures from the Company's claim based on his contentions that: (1) the NRC does not require decommissioning of non-radiological facilities; and (2) it is reasonable to assume that the Susquehanna site will not be totally abandoned and some existing facilities will continue to be used (OCA St. 4, pp. 18-20). As Mr. LaGuardia explained, Mr. Bridenbaugh is wrong on both counts.

While the NRC's regulations do not explicitly require the removal of non-radiological structures and equipment, the NRC has nonetheless dictated such site restoration as part of the delicensing process in many instances (PP&L St. 13-R, p. 3). More importantly, the destructive and invasive procedures used to ensure that no radioactive residue remains at the station site will leave the structures in an unstable and hazardous condition, as Mr. LaGuardia explained (PP&L St. 13, pp. 37-38):

> Efficient removal of the contaminated materials and verification that the radionuclide

> concentrations are below the stringent NRC limits will require substantial damage to many of the structures. Blasting, coring, drilling, scarification (surface removal), and the other decontamination work will damage power block structures including the Reactor, Radwaste and Turbine Buildings.
>
> Verifying that subsurface radionuclide concentrations meet NRC site release requirements may require removal of grade slabs and lower floors, potentially weakening footings and structural supports.

Regardless of NRC demands, non-radiological facilities would constitute "unsafe structures" subject to mandatory removal under applicable state and local laws and ordinances, such as the Building Officials and Code Administrators ("BOCA") National Building Code. Because the need to dismantle and remove non-radiological structures is caused by the radiological decontamination process itself, the distinction Mr. Bridenbaugh attempted to draw between radiological and non-radiological removal costs is artificial and unrealistic (PP&L St. 13, pp. 11-12; PP&L St. 13-R, pp. 2-3). For these reasons, the Commission has repeatedly held that non-radiological removal costs are properly includable in a utility's nuclear decommissioning claim:

> As also noted by the AIJ, there are safety considerations associated with this issue. The removal of contaminated facilities would severely damage a large portion of non-contaminated structures. Given current requirements both in Ohio and Pennsylvania regarding abandoned structures, the prudent course is to plan for the removal of <u>all</u> the structures.

Pa. P.U.C. v. Pennsylvania Power Co., 67 Pa. P.U.C. 91, 140 (1988). Accord Pa. P.U.C. v. Metropolitan Edison Co., 141 PUR4th 336 (1993); Pa. P.U.C. v. Duquesne Light Co., 66 Pa. P.U.C. 518 (1988); Pa. P.U.C. v. Pennsylvania Power Co., 85 PUR4th 323, 371-74 (1987).

Significantly, Mr. Bridenbaugh has previously acknowledged the prevailing precedent in Pennsylvania for allowing rate recognition of non-radiological removal costs. As the OCA's witness on decommissioning expense in Pa. P.U.C. v. Metropolitan Edison Co., supra, Mr. Bridenbaugh did not challenge the recognition of non-radiological costs for the Three Mile Island Unit 1. See, 141 PUR4th at 393.

Finally, Mr. Bridenbaugh's contentions regarding possible reuse of the Susquehanna site are based upon his misunderstanding of Mr. LaGuardia's cost estimate, which does not include any amount for the removal of facilities that might be reused (PP&L St. 13-R, p. 4):

> [M]y study does not provide for the removal of the basic structures for which it is reasonable to believe that a useful purpose will exist after decommissioning, such as the switchyard, transmission towers, culverts, head walls etc. It should also be noted that the decommissioning and removal activities that I have assumed involve only structures and equipment located within the restricted areas of the site.

For the reasons set forth above, the Company's claim for non-radiological dismantling and removal costs is reasonable, supported by substantial evidence and consistent with prior Commission decisions. Accordingly, the OCA's proposed adjustment should be rejected.

b. <u>Contingency</u>

Messrs. Bridenbaugh and Sivulich proposed a reduction in the Company's claim to remove the contingency Mr. LaGuardia had incorporated in his estimate of the costs of decommissioning radiological facilities. However, neither witness offered any reasonable basis for ignoring the cost factors that a contingency is designed to reflect. Indeed, neither witness attempted to reconcile his position with holdings of the FERC and numerous state commissions that have recognized a contingency factor in nuclear decommissioning cost estimates (PP&L St. 13, p. 24).

As Mr. LaGuardia explained, the purpose of a contingency is to allow for the costs of high probability program problems, where the occurrence, duration and severity cannot be accurately predicted and have not been included in the basic estimate. Past dismantling and decommissioning experience has shown that these problems are likely to occur and may have a cumulative effect. Examples of the most prevalent problem areas include schedule slippage (leading to overtime or project extensions), weather delays, labor strikes, worker injuries, material shipping problems, equipment breakdowns, regulatory inspections and hazardous materials handling (PP&L St. 13, pp. 22-23).

The inclusion of a contingency in cost estimation for both construction and dismantling is well accepted. The American Association of Cost Engineers recognizes the need for contingency allowances in engineering cost estimates. Similarly, the Atomic Industrial Forum's Guidelines Study for nuclear decommissioning explicitly validates the inclusion of a contingency in decommissioning cost estimates. In the Guidelines Study, individual contingencies, ranging from 10% to 75% were judged to be appropriate depending on the degree of difficulty associated with specific tasks. The overall contingency, when applied to the appropriate components of nuclear plant decommissioning costs, results in an average contingency of up to 25% (PP&L St. 13, pp. 22-23).

As previously indicated, regulatory commissions have generally approved contingencies of up to 25% in nuclear decommissioning cost estimates. The FERC adopted a 25% contingency for nuclear power plant decommissioning in the Middle South Energy/Grand Gulf Case (Docket ER82-616) (February 3, 1984). Additionally, numerous state commissions have adopted a 25% contingency for nuclear plant decommissioning, as evidenced by an AGA-EEI Depreciation Committee Survey, which showed that two-thirds of all survey respondents had previously approved such a contingency (PP&L St. 13, p. 24).

Additionally, and perhaps most importantly, TLG's actual experience in decommissioning nuclear power plants has confirmed the reasonableness of the contingency included in the SSES studies, as Mr. LaGuardia explained (PP&L St. 13-R, pp. 5-6):

> [I] believe that TLG's experience as the largest subcontractor in the decommissioning of the Shippingport Atomic Power Station provided a unique opportunity to test and confirm the reasonableness of our cost estimating methodology, including the use of contingency factors. All work on this program was competitively bid and required the highest degree of accuracy in estimating individual activity costs. TLG relied upon this same cost estimating methodology in preparing its bids for Shippingport that it used in developing the decommissioning estimates for Susquehanna SES. Not only was TLG a successful bidder at Shippingport, but the company was the only subcontractor to complete its assigned task(s) within budget and on schedule. This success provided field confirmation of TLG's empirical data base used to produce its estimates.
>
> The accuracy of TLG's estimates have also been confirmed in decommissioning activities undertaken at the Yankee Rowe, Shoreham, Pathfinder, and Rancho Seco Plants. Each estimate contained a level of contingency appropriate with the activities identified for the specified decommissioning program.

In summary, all of the available evidence -- published guidelines, decisions of state and Federal regulatory agencies and actual decommissioning experience -- support the use of a contingency and confirm the reasonableness of the level of contingency used by Mr. LaGuardia.

Mr. Bridenbaugh opposes the inclusion of a contingency because he contends that various "uncertainties" might cause some elements of decommissioning cost to turn out to be lower than Mr. LaGuardia estimated (OCA St. 4, p. 24-31). In each instance, however, the "uncertainty" Mr. Bridenbaugh identified would be unlikely to reduce costs and, in fact, is a potential cause of cost <u>increases</u> (PP&L St. 13-R, pp. 6-13).

The principal "uncertainty" cited by Mr. Bridenbaugh related to the estimate of $279 per cubic foot for disposal of low-level radioactive waste, which he claims might be excessive. Interestingly, to support his "uncertainty" argument, Mr. Bridenbaugh referenced studies and surveys that reported a <u>range</u> of current costs, the upper limit of which was as high as $1,300 per cubic foot (OCA St. 4, p. 25).

The figure of $279 per cubic foot used by Mr. LaGuardia represents the cost incurred by PP&L in 1993 for disposal of low-level radioactive waste. That value was judged to be a fair proxy for the minimum cost that would be incurred in the disposal of low-level radioactive waste within an as-yet-to-be-constructed regional facility. The development costs for an above-ground concrete facility, as proposed for a site in Pennsylvania, are significantly higher than the costs associated with a shallow-land facility, such as those used for current disposal. As a result, the $279 figure is very conservative (PP&L St. 13-R, p. 9).

The cost projections that have been used by other utilities for disposal at undeveloped regional facilities fully support the $279 per cubic foot value. For example, the Nebraska Public Power District relied upon a base rate of $350 in its 1993 decommissioning cost estimate for the Cooper Nuclear Station. Iowa Electric Light & Power also used $350 in its 1992 estimate for the Duane Arnold unit. Houston Lighting & Power Company used a projection made by the Texas Low-Level Radioactive Waste Disposal authority of $290/cubic foot in estimating waste disposal costs for the decommissioning of the South Texas Project. Michigan and Wisconsin utilities are currently using comparable values ranging between $300 to $400. The Wolf Creek Nuclear Operating Company relied upon a $300 value for estimating 1993 disposal costs for the Wolf Creek Plant in Kansas. Burial costs at the Callaway Plant in Missouri were estimated using $250 as a unit disposal cost in the same year.

In addition, it should be noted that the Arkansas Public Service Commission recently granted Arkansas Power & Light Company an increase in its decommissioning expense allowance to reflect increases in waste disposal costs. In so doing, the Commission approved a base disposal rate of $291.60. The Commission recognized that until a dependable projection of the rates for the Central States Compact was available, the then-current cost for disposal at the Barnwell, South Carolina site represented a reasonable proxy. Although, since 1994, the Barnwell site has been closed to waste from all but eight Southeast states, South Carolina recently passed legislation permitting the site to accept waste from across the country. However, disposal would be subject to a South Carolina state tax of $235 per cubic foot on top of the disposal cost of approximately $100 per cubic foot, or a total charge of approximately $335 per cubic foot (Wall Street Journal, June 15, 1995 (p. A5)).

Other "uncertainties" cited by Mr. Bridenbaugh to justify the removal of contingency are also misguided and based upon a lack of technical understanding:

Use Of The SAFSTOR Decommissioning Method. Mr. Bridenbaugh speculates that increases in waste burial costs might make the SAFSTOR decommissioning method[42] more attractive. However, he indicated on cross-examination that he was not advocating any particular decommissioning method. Moreover, based on analyses conducted by TLG, including those performed for purposes of this proceeding, the SAFSTOR option consistently generates a higher estimate than the DECON option, which was assumed for purposes of the SSES study (PP&L St. 13-R, pp. 11-12).

Technological Development/Experience Gained. Mr. Bridenbaugh also suggested that technological development and experience gained will reduce decommissioning costs in the future. However, as Mr. LaGuardia explained, if history is any guide, the opposite is more likely to be true, and nuclear decommissioning costs will continue to escalate at rates in excess of general inflation. Furthermore, Mr. LaGuardia

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[42] SAFSTOR entails "moth balling" the plant for a period of years before decontamination begins (PP&L St. 13-R, p. 28).

explicitly incorporated all "lessons learned" in his study of SSES decommissioning. If any subsequent advances in decommissioning technology are made, there will be ample opportunity to reflect their effect in future decommissioning cost estimates (PP&L St. 13-R, pp. 12-13).

License Extension. Mr. Bridenbaugh also postulated that the operating license for SSES might be extended, which would reduce the annual decommissioning accrual by spreading the total cost over a longer period. Mr. Bridenbaugh based his hypothesis on what he characterized as "discussion in the nuclear industry of extending the life of plants" (OCA St. 4, p. 29). However, at this point, license extension clearly has not left the "discussion" stage and, therefore, should not be used as the basis to artificially suppress known costs. Moreover, the current license life has been used, with Commission approval, to calculate the depreciation expense associated with SSES. In that context, no party has disputed the use of the license life to define the period over which SSES costs should be recovered.

Mr. Sivulich's objection to the inclusion of a contingency appeared to be based on his perception that the Commission has been unwilling to recognize this factor in prior decisions. In support of his position, Mr. Sivulich cited the Company's last base rate case, where a 25% contingency was rejected (OTS St. 2, p. 22). Mr. Sivulich's analysis is incorrect in several respects.

First, the Commission rejected the use of 25% contingency in PP&L's 1985 base rate case because the contingency was applied to cost estimates derived from generic decommissioning studies and without specific analyses of the areas likely to experience problems. Pa. P.U.C v. Pennsylvania Power & Light Co., 59 Pa. P.U.C. at 384. In contrast, in Mr. LaGuardia's site-specific study, he analyzed each area having a high probability for problems, delays or additional costs, and determined an appropriate contingency factor based on that analysis and the actual experience of dismantling and decontaminating nuclear plants (PP&L St. 13, pp. 21-25).

Second, at the time of the Company's last case, this issue had been addressed in relatively few jurisdictions, and the Commission relied upon a single decision from Massachusetts that purported to disallow a contingency. Id., p. 384. Since 1985, the weight of precedent from Federal and State regulatory agencies supports the use of a contingency factor, as previously explained.

Third, since PP&L's 1985 case, this Commission has approved decommissioning claims that included a 25% contingency. In fact, such studies were submitted by Mr. LaGuardia in base rate proceedings involving Pennsylvania Power Company. Pa. P.U.C. v. Pennsylvania Power Co., 85 PUR4th 323 (1987); Pa. P.U.C. v. Pennsylvania Power Co., 67 Pa. P.U.C. 91 (1983).

For the reasons set forth above, the inclusion of a contingency in PP&L's decommissioning cost estimate is appropriate, fully supported by the evidence and consistent with regulatory decisions from this and other jurisdictions. According, the adjustments proposed by Messrs. Bridenbaugh and Sivulich should be rejected.

c. <u>Trust Fund Earnings Rate</u>

As previously explained, Mr. Bernini employed an after-tax earnings rate of 5.5% on trust fund assets to calculate the annual annuity accrual for decommissioning costs. OCA witness Kahal and PPLICA witness Kollen have proposed adjustments to increase the trust fund earnings rate based on their disagreement with three aspects of the Company's claim: (1) the Company's decision to initially invest only 30% of the trust fund assets in common equities; (2) continued investment in tax exempt bonds; and (3) the assumed return on the common equity portion of the portfolio. Mr. Kahal has proposed an earnings rate of 7.5% based on 30% of the trust fund portfolio being invested in common equities producing an average annual return of 12% (OCA St. 1, pp. 58-60). Mr. Kollen proposed that the assumed earnings rate on fund assets should be set at the Company's proposed overall rate of return of 10.23% and that the Company "guarantee" that level of earnings (PPLICA St. 9, pp. 22-24). The arguments and positions espoused by Messrs. Kahal and Kollen are incorrect and should be rejected.

As explained by Mr. John M. Chappelear, PP&L's Vice President-Investments and Pensions, the principal defect in the opposing parties' proposals is their failure to consider the interrelationship between PP&L's proposed earnings rate on trust fund assets and the projected cost of decommissioning SSES. The Company's decommissioning claim is driven by two fundamental factors: (1) the expected cost to decommission the plant at retirement; and (2) the expected funds available in the trust to pay for decommissioning at that time. To calculate the projected decommissioning cost, a 1993 estimate was escalated at a rate of inflation (4.0%) equal to the expected increase in the Consumer Price Index ("CPI"). To calculate the funds expected to be available in the trust, the Company assumed an after-tax earnings rate of 5.5% on trust fund assets. Both estimates are conservative. The Company might earn more than 5.5% on the trust fund, but the cost of decommissioning the plant will likely increase at more than the estimated 4.0% change in the CPI. As explained by Mr. LaGuardia, the types of costs generally involved in decommissioning, particularly radioactive waste disposal, have historically increased at a rate well in excess of the general rate of inflation. Moreover, this conclusion was confirmed by Mr. Chappalear based on the experience of other utilities and the analyses of various decommissioning experts (PP&L St. 17-R, pp. 3-4).

If the opposing parties wish to employ more aggressive earnings assumptions, then they also should factor correspondingly higher inflation rates into the future cost of decommissioning the plant. However, even a relatively small increase in the inflation rate would more than offset increases in the earnings rate of the levels proposed by Messrs. Kahal and Kollen. This occurs because the inflation rate is applied to the total current cost of decommissioning the plant (approximately $723.8 million as of December 31, 1993) while the earnings rate is applied to the assets in the trust fund (projected to be approximately $98.3 million as of September 30, 1995). For example, use of an annual 6% inflation rate in the cost of decommissioning (2 percentage points higher than the Company's 4% figure) and Mr. Kahal's recommended annual 7.5% earnings rate (again 2 percentage points above the Company's claim) would increase the Company's claim by $8.7 million in this case (PP&L St. 17-R, p. 4). As should be evident, the Company employed conservative, interrelated assumptions on both sides of the equation, and it is unfair to tinker with one value while ignoring the associated effect on other values in that equation.

30% Equity Commitment. The Company's plan to invest 30% of the trust fund in common equities is reasonable in light of the Company's primary goal, which is to assure that sufficient funds are available to decommission SSES at its retirement. A cautious and relatively risk-adverse investment strategy is critical to achieving this result. A key consideration in this investment strategy is the fact that the plant will not be decommissioned over an extended period, but at a single point in time, which might be substantially sooner than expected in the event of a premature decommissioning event. No matter when decommissioning occurs, the necessary funds must be available. This is substantially different from the funding requirements for pensions, where the liability extends, with much greater certainty, over many years. As a result, PP&L can be somewhat more aggressive in its pension fund investments because payments from that fund are spread over a much longer payout period.

Additionally, if the Commission approves the Company's proposal to eliminate the "Black Lung" restrictions on its decommissioning trust fund, PP&L will begin to invest in common equities for the first time in late 1995 or 1996. It is a prudent and well-established investment strategy to implement major changes in asset allocation gradually in order to avoid the possibility of making major commitments at a market top and incurring substantial start-up losses. Such a conservative approach is particularly appropriate at this time because the stock market is trading at an all time high. The same approach will be used for beginning to phase out of equities well before the decommissioning funds are needed. This process of ramping up the equity exposure at the outset, and scaling it down at the end, will certainly lead to a <u>lower</u> overall <u>average</u> equity exposure than the maximum achieved level during the life of the trust. The Company's estimate of an <u>average</u> equity exposure of 30% over the life of the trust fund reflects this ramp-up and ramp-down (PP&L St. 17-R, p. 6).

Equity Portfolio Earnings Rate. It is not reasonable to assume that the long-term earnings rate on trust fund equity investments should equal the Company's claimed return on equity ("ROE") in this case for several reasons. First, the Company's claimed ROE is a short-term figure designed to reflect investors' expected returns for the future test year and the initial period new rates will be in effect. The earnings rate on the trust fund equity investments is a long-term figure designed to reflect the expected after-tax investment returns over the remaining life of SSES (PP&L St. 17-R, p. 7).

Second, the Company's claimed ROE in this proceeding is an opportunity rate of return which the Company may or may not achieve. It would be inappropriate to employ a short-term opportunity rate of return as an estimate of a long-term achieved return (PP&L St. 17-R, p. 7).

Finally, as explained above, the Company's expected return on equity investments in the trust fund is based on a 4% rate of inflation, which is consistent with projected increases in the cost of decommissioning SSES. If a higher equity return is employed for an estimate of earnings on the trust fund, then the expected rate of inflation also must be increased (PP&L St. 17-R, pp. 7-8).

Investment In Tax Exempt Bonds. As to this issue, Mr. Kollen simply misunderstand the facts. The Company's 5.5% estimated after-tax rate of return on fund assets does not reflect the use of tax exempt bonds. Rather, the Company's estimate was based upon after-tax rates of return on long-term government bonds and long-term corporate bonds (Tr. 420; PP&L St. 17-R, p. 8).

<u>"Guaranteed" Earnings Rate</u>. Mr. Kollen's proposal that the Company "guarantee" an earnings rate equal to its claimed overall rate of return is misguided and should be rejected. The Company is not in a position to guarantee the future results of the stock and bond markets -- nor is it appropriate to ask the Company to do so. While the Company can control the selection of its investments in the decommissioning trust fund, it clearly does not control the ultimate performance of those investments. As recent experience has demonstrated, returns on investments can vary dramatically for any number of reasons. For example, stock and bond markets are driven by inflation, interest rates and long-term economic trends. Similarly, trust fund returns are stated on an after-tax basis and are affected by tax rates and other tax policy changes. PP&L has no influence over any of these factors (PP&L St. 17-R, pp. 9-10). In this context, Mr. Kollen's proposal is illogical; the results could be punitive; and it should be rejected.

For all of the reasons set forth above, the Company's proposed after-tax earnings rate of 5.5% should be used to calculate the annual decommissioning accrual, and the opposing parties' adjustments should be rejected.

d. Post-Shutdown Earnings Accrual

The Company calculated an annual decommissioning annuity sufficient to provide all needed decommissioning funds at the time SSES 1 and 2 are retired. OCA witness Catlin proposed an adjustment to reduce the Company's annual annuity accrual by treating post-shutdown earnings on trust assets as funds available to meet PP&L's decommissioning commitment (OCA St. 6, pp. 21-22). Mr. Catlin contended that his proposal would not violate NRC rules because the NRC has purportedly accepted the funding plans of other utilities that recognized post-shutdown earnings. Mr. Catlin based his opinion on a telephone call to Mr. Robert Wood, the License Renewal/Environment Review Project Director at the NRC responsible for reviewing decommissioning funding plans. Additionally, Mr. Catlin asserted that Mr. LaGuardia was involved in formulating a decommissioning expense claim in Louisiana Power & Light Company's ("LP&L") pending rate case that allegedly recognizes post-shutdown earnings (OCA St. 6A, pp. 15-16).

Mr. Catlin's interpretation of NRC rules is simply wrong. As Mr. LaGuardia explained, the NRC requires that a nuclear decommissioning trust be fully funded in the amount necessary to terminate the license at the time of plant shutdown (PP&L St. 13-R, p. 14). PP&L, as the licensee, must abide by these requirements. Furthermore, Mr. Catlin apparently misunderstood what he was told by Mr. Wood. As Mr. LaGuardia testified, as recently as May 25, 1995 Mr. Wood had reaffirmed that NRC rules mandate full funding of the decommissioning project by the time of plant shutdown (Tr. 2075-76).[43]

Finally, contrary to Mr. Catlin's inference, Mr. LaGuardia did not prepare or sponsor LP&L's decommissioning expense claim in its pending rate proceeding, although TLG did prepare the underlying decommissioning plan. Consequently, whatever way LP&L decided to state its claim in that case does not impugn the accuracy or credibility of Mr. LaGuardia's assessment of NRC rules (Tr. 2076-77).

e. Amortization In Lieu Of Annuity

As previously explained, PP&L has proposed the use of an annuity method to calculate the annual decommissioning expense accrual. Mr. Sivulich has proposed dispensing with the annuity calculation and using, instead, a simple amortization method, which results in a decrease from the Company's claim. Under an amortization method, the current decommissioning cost estimate less the balance in the trust fund is divided by the remaining license life of the units to be decommissioned. Mr. Sivulich alleged that his proposed methodology is the same as that approved by the Commission in PP&L's last two rate cases (OTS St. 2, p. 23). Mr. Sivulich's proposal should not be

[43] As Mr. LaGuardia noted (Tr. 2075-76), Mr. Catlin's confusion may rest with the fact that an exception to the general rule has been made in the case where nuclear units were retired prematurely.

approved. The manner in which he calculated annual decommissioning expense deviates in important respects from the method approved in the Company's last case. Moreover, the simple amortization method can understate accruals and, thereby, cause under-funding that must be made up by large increases later in the life of the plant.

In the Company's last base rate case, the Commission approved a nuclear decommissioning expense allowance based on the "accrual method." However, in that case, the Commission permitted PP&L to recover deficiencies in prior accruals over a one year period. Mr. Sivulich ignored this aspect of the prior-case method. The simple accrual method he proposed has the effect of amortizing the current deficiency over the remaining life of the plant (approximately 30 years). If the method used in the Company's last case were to be adopted, then it should be used in the same manner as it was applied in the last case. As Mr. Bernini explained, if PP&L's claim were recalculated using the same method employed in its last rate case, its claim would be substantially higher (PP&L St. 3-R, p. 9).

Additionally, by amortizing the funding deficiency over the remaining life of the plant, as Mr. Sivulich proposed, future customers would be burdened with ever-increasing revenue requirements. This will result from both the increasing cost of decommissioning and the make-up adjustment being spread over a decreasing remaining life (PP&L St. 3-R, p. 9). In contrast, the annuity method provides a more levelized recovery of costs over the life of the plant.

The accrual method implicitly assumes that earnings on the trust fund will always be sufficient to offset increases in the cost of decommissioning. That is an unrealistic assumption. Even if the rate of increase in costs were substantially less than the earnings rate on the trust fund, there would still be a very substantial funding shortfall because the decommissioning cost (over $700 million) is considerably larger than the current balance in the trust fund (less than $100 million) (PP&L St. 3-R, pp. 9-10).

Accordingly, for all of the reasons set forth above, the annuity method should be used to calculate the Company's decommissioning expense in this case and Mr. Sivulich's proposed alternative should be rejected.

2. Fossil Decommissioning Expense

PP&L has proposed to establish an annuity, similar to the one used to fund nuclear decommissioning expense, to recover the cost of dismantling and demolishing its fossil-fired generating plants following their retirement from service.[44] The Company

[44] The Company's fossil decommissioning claim includes 14 units currently in service and two units (Holtwood 15 and 16) that have already been deactivated. The deactivated units would not be dismantled until the retirement of the last operating unit at Holtwood. In that way, all decommissioning work can be done at one time in order to achieve economies of scale and reduce total costs (PP&L St. 13, p. 3)

has included \$55.6 million in its claimed operating and maintenance expenses (\$45.3 million on a PUC jurisdictional basis) for the annual payment needed to annuitize total fossil plant decommissioning costs of \$628.5 million (PP&L Ex. Future 1 - Revised, Sch. D-12; PP&L St. 13, p. 3). Because payments to a fossil decommissioning trust are not deductible for Federal income tax purposes, only the after-tax portion of the amount allowed in rates would be deposited in the fund.

The Company's decommissioning cost estimate was developed by Mr. LaGuardia based on detailed site-specific studies of PP&L's fossil plants and well-accepted cost-estimation techniques (PP&L St. 13, pp. 20-22). Mr. LaGuardia has prepared numerous decommissioning studies for utility-owned and non-utility fossil-steam facilities (PP&L St. 13, pp. 9-10). The annual annuity figure was derived by Mr. Bernini using the same methodology, inflation rate (4%) and earnings rate (5.5%) he employed for the nuclear decommissioning annuity calculation (PP&L St. 3, p. 22). The annual payments needed to annuitize the decommissioning cost of each fossil unit have been calculated on a unit-specific basis (PP&L Ex. Future 1 - Revised, Schedule D-12, pp. 2-6).

The Company recognizes that its proposal to recover decommissioning costs during the remaining operating lives of its fossil plants is a departure from the way those costs would be handled under existing ratemaking procedures. Thus, absent Commission approval of the Company's proposal, decommissioning costs would be recoverable as a form of net negative salvage. For the reasons discussed below, however, PP&L believes that its recommended approach is far more reasonable and should be adopted.

Under current practice, net negative salvage is recorded as a deduction to accrued depreciation, and a five-year average of experienced net negative salvage is added to a utility's annual depreciation expense accrual. See Pa. P.U.C. v. Pennsylvania-American Water Co., Docket No. R-00932670 (July 26, 1994)(Order, pp. 32-35). Consequently, net negative salvage may be recovered only after it has been incurred and, at that point, it is charged to customers over a subsequent five-year interval.

The net negative salvage cost recovery method is adequate for the relatively small removal costs associated with ordinary retirements of individual units of mass property and interim retirements of components of larger facilities, which typically occur in the course of ordinary maintenance. However, as applied to the significant expenditures necessary to decommission entire generating facilities, that method would result in an inequitable distribution of costs among different generations of customers (PP&L St. 4-R, p. 16).

The deficiencies inherent in using the net negative salvage method to recover fossil plant decommissioning costs are readily apparent when potential cost impacts are considered. For example, by the estimated retirement dates for the Brunner Island

(2014) and Montour (2017) Steam Electric Stations, the decommissioning costs for those facilities will be $368.3 million and $330.0 million, respectively (PP&L Ex. Future 1, Sch. D-12, pp. 3-4). The five-year amortization of those costs would peak at approximately $139.7 million per year ($368.3 million + $330.0 million ÷ 5 years). As a result, customers who would no longer be receiving any service from those facilities would experience a substantial rate "spike" to pay the cost to decommission them.

In contrast to the rapid and substantial rate increase that the net negative salvage method would produce, the Company's proposal would recover the Brunner Island and Montour decommissioning costs in annual installments of approximately $18 million over the remaining lives of those plants (PP&L Ex. Future 1, Sch. D-12, pp. 3-4). Not only would abrupt increases in future rates be avoided, but the costs of decommissioning would be borne by the customers who are actually benefiting from the energy generated by those facilities. In that way, the Company's proposal would assure inter-generational equity in the payment of all costs associated with the operation of its generating plants.

Additionally, pre-funding of fossil decommissioning costs is a reasonable response to the significant public health and safety concerns that attend the retirement and dismantling of generating facilities. As Mr. LaGuardia explained, retired generating plants would be "unsafe" structures, as defined by the BOCA Code, and would have to be taken down and removed or made safe and secure (PP&L St. 13, pp. 11-12). Additionally, a considerable part of the cost of decommissioning fossil plants is caused by special handling procedures for hazardous materials, such as asbestos, PCBs and lead-based paint, and by the need to dispose of such materials in an environmentally-sound manner (PP&L St. 13-R, pp. 18-19).

Annuitizing decommissioning costs, as the Company has proposed, will assure that public health and safety risks are adequately addressed upon the retirement of its fossil generating facilities. Indeed, that is precisely the rationale underlying the establishment of nuclear decommissioning trust funds. Given what is now known about the pernicious effects of hazardous but non-radioactive materials and substances present or incorporated in fossil plants, it is clear that the same kinds of public health and safety concerns which drove the creation of nuclear decommissioning trust funds justify the pre-funding of fossil decommissioning.

The Company is aware that the Commission recently rejected a request by West Penn Power Company to accrue fossil plant decommissioning costs. <u>Pa. P.U.C. v. West Penn Power Co.</u>, Docket No. R-00942986 (December 29, 1994)(Order, pp. 59-63). Nonetheless, the Company firmly believes that this issue should be revisited because of the greater magnitude of these costs for

PP&L and the severe impact on future customers that is certain to result if cost recovery is deferred.[45]

Opposing party witnesses have taken issue with the Company's fossil decommissioning expense claim on two bases. First, Messrs. Sivulich, Catlin and Kollen propose that PP&L's claim be rejected in its entirety and the net negative salvage method be relied upon for after-the-fact cost recovery. Second, Messrs. Kahal and Kollen contend that, if the claim is allowed, a substantially higher earnings rate on trust fund assets should be assumed. Each of these issues is discussed below.

a. Net Negative Salvage

Messrs. Sivulich, Catlin and Kollen have offered two basic arguments for their opposition to the Company's claim for fossil decommissioning costs: (1) that such claims are prohibited by the Pennsylvania Superior Court's decision in Penn Sheraton Hotel Co. v. Pa. P.U.C., 198 Pa. Super. 618, 184 A.2d 324 (1962); and (2) that after-the-fact amortization of net negative salvage is a more appropriate recovery mechanism. Neither argument is a valid basis for disallowing the Company's claim.

Penn Sheraton. In Penn Sheraton, the Superior Court held that a steam heat utility could not include in its depreciation

[45] West Penn claimed an annual annuity expense of $1.46 million for the cost to decommission four jointly-owned power stations. West Penn, supra, p. 59. West Penn's lower annual annuity cost reflects a lower overall decommissioning exposure.

expense accrual an allowance for the future cost of dismantling and removing steam mains upon their retirement. Consequently, Penn Sheraton is typically cited for the proposition that current recovery of prospective net negative salvage is not permitted in Pennsylvania. However, a notable exception to that general principle has been recognized to permit the accrual of decommissioning costs for nuclear generating facilities. That exception has been reconciled with Penn Sheraton on the grounds that the significant health and safety risks associated with the closure of nuclear facilities justifies the creation of a decommissioning fund. See Pa. P.U.C. v. West Penn Power Co., 54 Pa. P.U.C. 602 (1980).

Modern science has provided increased knowledge about the health and safety risks associated with materials and chemicals present in fossil-fired generating plants. Concerns about these risks have been manifested in the stringent environmental and occupational safety regulations that apply to nearly all aspects of fossil plant dismantling and removal, as Mr. LaGuardia explained (PP&L St. 13-R, pp. 18-19):

> Virtually all older fossil-fueled plants have asbestos, PCBs, lead-painted surfaces, acids and caustics. All work in abating and removing these materials is extremely hazardous for which trained professionals must be retained. Federal and state regulations require workers to have complete medical examinations including electrocardiograms, x-ray examinations, and pulmonary function tests. All workers must successfully complete 32 hours of asbestos removal training (40 hours for supervisors, additional 8-hour courses for asbestos sampling technicians). Workers are

required to wear full protective clothing (coveralls, boots, gloves, caps), and wear air purifying or supplied air masks for respiratory protection, and carry and monitor portable air samplers.

In addition, all work must be performed in double-walled tents maintained under negative pressure. Upon leaving an asbestos work area, workers are required to remove their protective clothing (but not their respirator), and shower to remove residual asbestos fibers. After showering, they enter a third enclosure to remove the respirator and change into street clothes. This process is repeated at least four times a day when considering the need for breaks and lunch. All materials brought out of the work area (asbestos materials, tools and equipment) and into a "cargo area," must be double bagged, stripped of the outer bag in the cargo area, and rebagged for disposal or storage.

Similarly, workers involved in cutting lead-painted surfaces for any cutting technique are required to have separate, but similar training for worker safety and lead contamination control.

The hazardous nature of the work required to dismantle fossil-fired generating plants, and the risks to the public of not performing that work properly, clearly justify extending to fossil plant decommissioning the same "health and safety" exception to Penn Sheraton permitted for nuclear facilities. In that regard, the opposing parties are simply not correct in contending that fossil decommissioning should be prohibited as a matter of law because of the Penn Sheraton holding.

After-The-Fact Amortization. None of the witnesses who recommended after-the-fact amortization offered any quantitative analysis of the customer impact or inter-generational equity problems that method would create if it were applied to costs approaching the magnitude of the Company's decommissioning estimates. Mr. Sivulich's attempt to address this issue consisted of the assertion that, because "present customers are paying for the removal of some plant that served previous generations of ratepayers," the Commission should not be troubled if the cost of decommissioning existing generating plants is imposed on future customers (OTS St. 2, pp. 16-17).

In addition to the shortsightedness of Mr. Sivulich's approach, his premise is factually incorrect because "present customers" are <u>not</u> bearing any fossil plant decommissioning costs. In fact, in the last 23 years, PP&L has decommissioned <u>one</u> generating unit, which was a small (23 MW) combustion turbine that caused only nominal removal costs (PP&L St. 4-R, p. 15). When major steam generating facilities, such as those PP&L currently operates, are retired, decommissioning costs will be incurred sporadically and in very large amounts. Mr. Sivulich's assumption that these costs are experienced more-or-less evenly over different generations of customers is simply wrong. For that reason, a decommissioning accrual over the remaining lives of the Company's existing fossil-fired plants provides a more equitable distribution of costs among current and future customers.

The opposing parties further contended that current estimates of decommissioning costs were "speculative" and, therefore, it would be preferable to defer recovery of such costs until they have been incurred. These arguments also lack substance, for several reasons.

Messrs. Sivulich, Catlin and Kollen have characterized PP&L's decommissioning claim as "speculative" simply because it is based on estimates that incorporate assumptions about future events (OCA St. 2, pp. 13-14). However, numerous ratemaking allowances are based on long-term assumptions which may require modification in subsequent rate cases. In fact, the Commission has held that the ability to adjust future accruals to reflect refinements in cost estimates dispels any concerns that decommissioning costs are too "speculative" to be recognized in the ratemaking process:

> It is true that the total costs of decommissioning a nuclear power plant cannot now be determined with precision and may be termed speculative by some . . . Changes in the estimates of decommissioning costs may be dealt with through periodic review and adjustment of the total estimate (and its annual provision) within each rate case, or at any time upon the initiative of the commission when it feels that such review is necessary.

Pa. P.U.C. v. Pennsylvania Electric Co., 51 Pa. P.U.C. 649, 669 (1978).

Stated simply, there are numerous categories of expense the precise quantification of which will not be known for years to come. However, as the Commonwealth Court has held, the mere fact that a claim is based on estimated data does not render it unduly "speculative" for ratemaking purposes. Columbia Gas of Pennsylvania, Inc. v. Pa. P.U.C., 149 Pa. Cmwlth 247, 254-255, 613 A.2d 74, 77-78 (1992), aff'd per curium 535 Pa. 517, 636 A.2d 627 (1994)("[A] sufficiently detailed projection is not speculative -- it is in the nature of prospective ratemaking for utilities to make projections as to all aspects of their operations . . . "). The appropriate regulatory response is not to pretend that the underlying obligation does not exist, but rather to develop the best estimate possible given the current information.

As the evidence in this case demonstrates, Mr. LaGuardia has made a sound, reasonable and fully documented estimate of PP&L's fossil decommissioning costs. Although opposing party witnesses criticized Mr. LaGuardia's studies in a general and superficial manner, none of those criticisms has any factual basis, as Mr. LaGuardia demonstrated in a point-by-point response (PP&L St. 13-R, pp. 14-17). Moreover, all of Mr. LaGuardia's "assumptions" are extremely conservative and, as a result, the most probable outcome is that actual events will produce higher costs than he has estimated (PP&L St. 13-R, p. 16).

b. Trust Fund Earnings Rate

Messrs. Kahal and Kollen have also opposed the Company's fossil decommissioning expense claim on the ground that the trust fund earnings rate used in the annuity calculation is too low. This is the same criticism that was made of the Company nuclear decommissioning annuity calculation and, for reasons set forth in the discussion of that issue, the opposing parties' position should be rejected.

C. Depreciation Expense

PP&L has claimed an annual depreciation and amortization expense allowance of $320,797,000 based on the calculations performed by Mr. Hoch (PP&L St. 4). Except for certain General Plant Accounts and pre-1989 investment in SSES, the Company's claim was derived through the application of the straight-line remaining life method of depreciation.

For transmission, distribution and non-amortized general plant, the average service lives and retirement dispersions used to calculate annual depreciation accrual rates were determined on the basis of a service life study completed in 1993 (PP&L Ex. DSH-1). The actuarial techniques used in the 1993 study were the same as those employed in earlier studies that had been approved in prior base rate proceedings. For steam, nuclear, hydro and other production facilities, the life span system, rather than the average service life method, was employed. Under life-spanning, the annual depreciation accruals must be sufficient to recover the Company's investment in each facility by its estimated deactivation date (PP&L St. 4, pp. 4-8).

As a result of the 1993 service life study and updated analyses of production facilities, several changes were made in the estimated service lives and life spans of the Company's property for purposes of calculating depreciation expense. The principal changes consisted of the following:

- Unit-specific deactivation dates were adopted for SSES 1 and 2, which extended the proposed deactivation date of SSES 1 by approximately one month and the proposed deactivation date of SSES 2 and all common plant by approximately two years. As a result of this change, the annual depreciation expense allowance for SSES was reduced by approximately $1.3 million (PP&L Ex. DSH-1, Section 1).

- The average service lives of some transmission and distribution facilities were increased and, as a result, the associated annual depreciation expense allowance was reduced by approximately $18.9 million (PP&L Ex. DSH-1, Section 1; PP&L St. 4, pp. 4-5).

- The life spans for the jointly-owned, coal-fired Keystone and Conemaugh Steam Electric Stations were increased by five years each, with a resulting reduction in the annual depreciation expense allowance of approximately $3.8 million (PP&L Ex. DSH-1, Section 1; PP&L St. 4, p. 5).

- The deactivation dates of the coal-fired Sunbury Steam Electric Station Units 1, 2, 3 and 4 ("Sunbury"), Martins Creek Steam Electric Station Units 1 and 2 ("Martins Creek 1 and 2") and Holtwood Steam Electric Station Unit 17 ("Holtwood") (collectively, "the older fossil-fired units") were accelerated by 7, 12 and 6 years, respectively. As a result, the associated annual depreciation expense allowance was increased by approximately $18.7 million (PP&L Ex. DSH-1, Section 1; PP&L St. 4, p. 6)..

In addition to the aforementioned changes in service lives and deactivation dates, the Company has proposed two other revisions in the way it depreciates its utility property. First, the Company has proposed "levelizing" the Modified Sinking Fund

("MSF") depreciation expense for pre-1989 vintage SSES property that will accrue between September 30, 1995 (the effective date of rates in this case) and December 31, 1998, when SSES depreciation will switch from MSF to straight-line. As more fully explained hereafter, this proposal modifies only the timing, not the amount, of the depreciation to be charged during that approximately three-year period.

Second, the Company has proposed the adoption of amortization accounting for certain General Property Accounts, which consist of numerous small value items. Amortization accounting will reduce the time, resources and recordkeeping necessary to maintain detailed plant data for such property while providing a reasonable mechanism for the accurate and timely recovery of invested capital. For that reason, the Commission has previously approved the conversion to amortization accounting for small value accounts for other utilities (Tr. 1848).

Witnesses on behalf of the OTS, the OCA, PPLICA and DOD have disputed one or both of PP&L's claims to levelize MSF depreciation for pre-1989 SSES investment and to reflect slightly shorter depreciable lives for its older fossil-fired units. In addition, the OCA's witness has taken issue with PP&L's proposal to adopt amortization accounting for small value general property. For the reasons set forth below, the opposing parties' objections are unsupported, and the Company's depreciation claim should be approved in its entirety.

1. Pre-1989 SSES Investment

Currently, PP&L depreciates the cost of SSES facilities placed in service prior to January 1, 1989 using the MSF method. MSF depreciation was proposed by PP&L and approved by the Commission in the rate proceedings at Docket Nos. R-822169 and R-842651 as a means of moderating the rate increases associated with including SSES 1 and 2 in rate base. Under the MSF method, the annual depreciation expense began well below the straight-line amount and increases each year until December 31, 1998, when: (1) annual MSF depreciation expense will substantially exceed the straight-line amount; and (2) total accrued depreciation on pre-1989 investment will equal the amount that would have accrued if straight-line depreciation had been used since SSES 1 and 2 were first placed in service[46/] (PP&L St. 4, pp. 10-11; PP&L Ex. Future 1 - Revised, p. 9).

In this filing, the Company is requesting permission to set the depreciation expense for pre-1989 SSES investment at a levelized annual total Company amount of approximately $173 million. This depreciation allowance will recover the same amount of depreciation that would have been recovered by the MSF

46/ The significance of December 31, 1998 derives from the Statement of Financial Accounting Standards No. 92 ("SFAS 92"). SFAS 92 established accounting standards for "phase-in plans," which were defined to include sinking fund and modified sinking fund depreciation techniques. In order to comply with SFAS 92, PP&L has until December 31, 1998 to recover the same amount of depreciation it would have recovered had the straight-line method been used for SSES 1 and 2 (PP&L St. 4, pp. 11-12).

method during the period from September 30, 1995 to December 31, 1998, as shown by the comparative data in PP&L Exhibit DSH-3.

As previously indicated, as of January 1, 1999, the depreciation of pre-1989 SSES investment will switch to the straight-line method, and annual depreciation expense for such property will fall to $102 million per year on a total Company basis. If the Company's proposal to levelize MSF depreciation is adopted, it would agree to automatically adjust its retail rates, as of January 1, 1999, to reflect the applicable PUC jurisdictional portion of this expense reduction (PP&L Ex. Future 1, p. 9; PP&L St. 4, p. 13).

The Company's proposal will result in a more equitable distribution of depreciation expense during the remaining period that the MSF method is in effect. Initially, it should be emphasized that the Company's proposal will not increase the amount of depreciation to be recovered between September 30, 1995 and December 31, 1998. Only the timing of recovery is affected. During that period, depreciation expense will be charged in equal annual installments. This equal distribution of depreciation expense over time replicates the straight-line method, which is universally accepted as a fair and reasonable method of capital recovery (PP&L St. 4-R, pp. 2-3).

Additionally, the Company's proposal will smooth the transition from MSF to straight-line depreciation that will occur in 1999. Without levelization, annual accruals would increase to

$194 million on a total Company basis in 1998, before dropping to $102 million in 1999 -- a one-year change of $92 million (see PP&L Ex. DSH-4).

Finally, because MSF annual accruals will increase markedly between 1996 ($157 million) and 1998 ($194 million), they are likely to drive PP&L's need to file more frequent base rate cases in order to assure that its rates are actually recovering the depreciation expense being booked each year. The transaction costs associated with more frequent rate filings would be an additional, avoidable revenue requirement burden for customers (see PP&L St. 4-R, p. 3).

Mr. Joseph J. Sivulich, on behalf of the OTS, opposed the Company's proposal, and listed four points to support his position (OTS St. 2, pp. 32-33). Two of those points are essentially the same, i.e., that continuing the MSF method will result in a lower revenue requirement "in the present case." As Mr. Hoch explained, while Mr. Sivulich's statements are accurate as far as they go, they do not provide a valid basis for rejecting the Company's proposal (PP&L St. 4-R, pp. 2-3):

> The ultimate decision to approve or reject the Company's proposal for levelizing MSF depreciation should be based on the substance and the merits of that proposal, including whether it results in fair treatment of the Company and its customers in light of all of the facts. Indeed, if Mr. Sivulich's contentions were accepted at face value as the appropriate way to assess depreciation methods, then the MSF method would be used for <u>all</u> utility property. However, straight-line

> depreciation is the method consistently used by utilities and approved by the Commission.

Additionally, Mr. Sivulich completely ignored the <u>future</u> consequences of a short-sighted rate minimization approach. Continuing MSF depreciation on its current basis would produce a "lower revenue requirement" in this case <u>only</u> because that method requires <u>increasing</u> levels of depreciation expense each year through 1998 (PP&L St. 4-R, p. 3).

Furthermore, the same factor that produces "lower revenue requirement . . . in the present case" totally undercuts Mr. Sivulich's fourth point, that continuing MSF until 1999 "will not prevent the Company from recovering all of the depreciation expense that it is entitled to," as Mr. Hoch explained (PP&L St. 4-R, p. 3):

> Because the "present MSF" method requires increases in depreciation each year until 1999, the Company could <u>not</u> be assured of recovering all of the depreciation expense that "it is entitled to" unless it made annual rate filings that reflect those annual depreciation changes as well as all other factors impacting its revenue requirement. Although there are a number of considerations affecting the decision whether to file a base rate increase request, rejection of the proposal to levelize MSF depreciation could only result in an additional factor driving the need for rate filings during the period through 1998.

Finally, Mr. Sivulich's observation that the proposed levelization of MSF depreciation "is not mandated by the Financial Accounting Standards Board" is no reason to reject the

Company's proposal. Although the Commission, in setting rates, clearly should consider the Financial Accounting Standard Board's pronouncements, most issues raised in rate proceedings are not subject to mandates by the Board. Consequently, as with those kinds of issues, the Company's levelization proposal should be analyzed on its own merits. For the reasons previously discussed, levelizing MSF provides substantial advantages that fully support the adoption of the Company's proposal.

Dr. Charles E. Johnson, on behalf of the OCA, and Mr. Lane Kollen, on behalf of PPLICA, opposed the Company's levelization proposal on the grounds that it fails to account for the effect on rate base and return that would result, prospectively, from such a depreciation change. Specifically, both contend that MSF inherently "levelizes" <u>all</u> after-tax fixed costs (depreciation and return) because increases in MSF depreciation from year to year would be fully offset by corresponding decreases in required return. Dr. Johnson and Mr. Kollen assume that such year-to-year reductions in return will occur because of declining rate base caused by the increase in <u>accrued</u> depreciation. In short, they contend that accrued depreciation is a source of so-called "negative attrition" (OCA St. 5, pp. 5-6; PPLICA St. 2, pp. 17-18).

While the argument advanced by the OCA and PPLICA witnesses has a number of flaws, its principal defect is due to the use of a static analysis of rate base. Their argument could be correct only if one assumes that the Company will not make any new investment in plant after rates are put into effect. Obviously, that is a totally unrealistic assumption. As Mr. Hoch explained, the Company's annual investment in new plant will, in all likelihood, exceed the reductions in rate base attributable to accrued depreciation (PP&L St. 4-R, p. 5). As a consequence, growth in PP&L's rate base is a source of attrition and, therefore, would drive the need for future rate relief. Rejecting the Company's proposal to levelize MSF depreciation would only contribute to attrition, accelerate the need for future rate relief and potentially increase the frequency of rate filings.

Mr. Kollen also asserted that the Company's levelization proposal is an attempt "to reach beyond the end of the test year for a projected cost increase" and, therefore, violates the test year concept. In that regard, Mr. Kollen is also mistaken. Furthermore, the "negative attrition" argument that Mr. Kollen and Dr. Johnson rely upon represents exactly the kind of attempt to anticipate post-future test year events that Mr. Kollen has criticized.

As previously explained, the Company has proposed recovering in equal annual installments -- that is, on a straight-line basis -- the same amount of total depreciation it would recover under MSF between September 30, 1995 and December 31, 1998 for pre-1989 vintage SSES property. In view of the fact that PP&L employs a straight-line method to depreciate the rest of its plant-in-service, its proposal to levelize SSES MSF depreciation through 1998 could hardly be regarded as an inappropriate deviation from standard depreciation practice that attempts to "reach beyond the end of the test year," as Mr. Kollen asserted.

Moreover, it bears repeating that it was Mr. Kollen and Dr. Johnson who employed a post-future test year analysis to support their argument that MSF depreciation levelizes total after-tax fixed costs. In essence, they tried to project future accrued depreciation balances and argued that, in anticipation of future increases in accrued depreciation, which they assume will reduce rate base from the current level, the lower depreciation expense produced by MSF in this case is fully justified. This kind of post-future test year projection is not appropriate. But, if such a projection were to be made, then post-future test year plant additions should also be considered.

The test year concept assumes that the relative relationship of various rate base components will remain about the same from year to year. Thus, for example, while accrued depreciation may increase, other changes -- such as additional investment -- will offset that reductive effect on rate base. In short, a kind of dynamic stability among rate base components is assumed. Significantly, the straight-line method, which is designed to recover depreciation at a levelized annual rate, is the predominant depreciation method employed for ratemaking purposes in Pennsylvania. Clearly, if there were any inconsistency between the use of levelized depreciation and the test year concept, the virtually universal acceptance of straight-line depreciation would not have occurred (PP&L St. 4-R, pp. 6-7).

Finally, Mr. Kollen characterized the Company's proposal as an "acceleration of the depreciation recovery" and as "prematurely collecting" depreciation from customers (PPLICA St. 2, pp. 17-18). Neither characterization is correct. For the reasons explained by Mr. Hoch (PP&L St. 4, pp. 10-13), a significant portion of the depreciation expense that remains to be recovered during the period from September 30, 1995 to December 31, 1998 consists of depreciation that would have been recovered long before now if straight-line depreciation, rather than MSF, had been used since SSES 1 and 2 were first included in PP&L's rate base. What Mr. Kollen refers to as an "acceleration," in fact relates to the recovery of depreciation that was <u>deferred</u> from prior years under the operation of the MSF method (PP&L St. 4-R, p. 7).

For the reasons discussed above, the Company's proposal to levelize MSF depreciation for pre-1989 vintage SSES property should be approved.

2. <u>Depreciable Lives Of The Older Fossil-Fired Units</u>

PP&L's depreciation expense claims for Sunbury, Martins Creek 1 and 2 and Holtwood reflect a deactivation date of 2003, which results in life spans that are, respectively, 6, 12 and 7 years shorter than those currently being used to depreciate those units (PP&L St. 5, pp. 9-10). However, the proposed life spans are actually somewhat longer than those approved in the Company's last rate proceeding (PP&L St. 5-R, p. 4). In that case, the deactivation dates used to calculate the Company's depreciation expense claim were 1994 (Holtwood), 1995 (Martins Creek 1 and 2) and 2000 (Sunbury). In 1988, in conjunction with other depreciation changes which were made outside of a base rate proceeding, the Commission approved PP&L's proposed extension of the depreciable lives of its the older fossil-fired units to reflect deactivation dates of 2009 (Holtwood), 2015 (Martins Creek 1 and 2) and 2010 (Sunbury) (PP&L St. 5-R, p. 4).

When the 1988 revisions were made, the Company anticipated that standard life extension techniques would make it economically justifiable to continue to operate the older fossil-fired units until the extended deactivation dates. However, at that time, the Company could not have foreseen the substantial costs that would be required to comply with the 1990 Clean Air Act Amendments ("CAAA"). Those costs dramatically altered the economics of life extension for the older fossil-fired units. In fact, the projected CAAA compliance costs would almost double the depreciated original cost of those units, as shown by the following data presented by Mr. Krall (Tr. 1875-76):

	Depreciated Original Cost (2003) Exclusive of Clean Air Act Compliance Costs	Capital Additions For Clean Air Act Compliance
Sunbury	$125.6	$ 98.5
Martins Creek 1 and 2	92.2	94.0
Holtwood	19.4	12.5
Total	$237.2	$205.0

The proposed deactivation date of 2003 is a watershed year. By that time, PP&L will have to achieve final compliance with stringent nitrogen oxide ("NO_x") limitations imposed under Title I of the CAAA and expects to make significant reductions in emissions of "air toxics" as mandated by Title III of the CAAA (PP&L St. 5, pp. 10-11). Simply stated, by the year 2003, PP&L either must have deactivated its older fossil-fired units or have made significant investments to achieve environmental compliance. The operation of those units beyond 2003 is highly uncertain because of a combination of factors that make it unlikely that the investments necessary for life extension will be economically justifiable. The factors bearing on that determination were outlined by Mr. Krall, as follows (PP&L St. 5-R, pp. 2-3):

1. The in-service dates of these units range from 1949 to 1954 making them currently between 40 and 45 years old. Given that power plant equipment of that vintage was typically designed for 30 to 40 years of operation, it is not surprising that significant equipment replacement needs are being identified.

2. These relatively old power plants operate at lower temperatures and without some of the design features of newer plants and, consequently, produce electricity less efficiently than newer plants.

3. A significant number of environmental issues are expected to affect power plants in general and coal-fired power plants in particular around the Year 2003. The Company's specific concerns are for NO_x reduction requirements expected to be defined in order to achieve ozone attainment in the Northeast under Title I of the 1990 Clean Air Act Amendments, and reductions in emissions of air toxics which may be required under Title III of the 1990 Amendments. Compliance with these requirements will require the installation of two different control systems.

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

It is our judgement that the combination of these factors makes the continued operation of these units beyond this time frame less certain that it was thought to be in 1988 when the current deactivation dates were established.

Use of the Company's proposed deactivation dates to calculate depreciation expense for its older fossil-fired units is totally justified in view of the considerable uncertainty as to whether those units will continue to be operated after 2003. In that regard, the Company's proposal is consistent with the concept that current customers should bear prudent costs incurred on their behalf. To ignore the probability of deactivation in 2003 would put future customers unnecessarily at risk to pay for the recovery of invested capital that is no longer providing current service to them.

Witnesses on behalf of the OTS, the OCA, PPLICA and DOD have disputed the Company's claim for shorter life spans for its older fossil-fired units. Although their principal arguments will be addressed in detail hereafter, there are several key defects at the heart of each of the opposing parties' positions, as outlined below.

First, the opposing parties have attempted to minimize the significance of PP&L's analysis of CAAA compliance costs by characterizing it as "speculative." However, none of the opposing party witnesses has identified any specific fact, assumption or analytic technique used by PP&L that he believes to be erroneous or unreasonable. Indeed, none of the opposing party witnesses even purported to have a working knowledge of the intricacies of the CAAA. In contrast, Mr. Krall amply demonstrated his comprehensive, in-depth understanding of the CAAA itself, the regulatory process for implementing it and the environmental science on which regulatory decisions will be based (Tr. 1932-1935). Simply stated, the Company has identified real and substantial risks to the continued operation of its older fossil-fired units beyond 2003. In accordance with well-accepted depreciation procedures, the Company has reflected those potential causes of retirement in its life span analysis. The opposing parties, in effect, suggest that such risks simply be ignored.

Second, the analyses prepared by PP&L as the basis for selecting a deactivation date of 2003 employ the same kind of analytic techniques regularly relied upon to determine the probable retirement dates of utility facilities for depreciation purposes. Inexplicably, the opposing parties seem to demand a greater degree of certainty in determining the life spans of the Company's older fossil-fired units than is possible for <u>any other</u> utility property. Indeed, none of the opposing party witnesses questioned the "certainty" of PP&L's life estimates that resulted in <u>longer</u> depreciable lives for other generating units and for transmission and distribution facilities. Apparently, the opposing parties "certainty" test is only applied to changes that increase, even modestly, the Company's depreciation expense claim.

Third, the opposing parties have argued in favor of recognizing life extensions of the Company's older fossil-fired units for purposes of <u>reducing</u> depreciation expense in this case, but have <u>ignored</u> the substantial capital additions that unquestionably would be required in order for such life extensions to occur. Therefore, their proposal would result in a totally inequitable distribution of revenue requirement over the lives of those units, assuming that life extensions actually occurred. Specifically, under the opposing parties' approach, current customers would benefit from an $18.7 million per year <u>reduction</u> in depreciation expense between 1996 and 2003. However, the assumed extension of the lives of the Company's older fossil-fired units that would make such a reduction possible would be purchased at the expense of future customers, whose revenue requirement burden associated with those units would nearly double because of the cost of CAAA capital additions going in service by 2003. Stated another way, the opposing parties' proposal would defer approximately $150 million of capital recovery ($18.7 million per year for 8 years) to the period from 2004 to the end of the extended lives of the Company's older fossil-fired units. However, during the same post-2003 period, customers would also bear over $30 million[47/] per year of additional revenue requirement associated with CAAA capital additions.

Mortgaging the future to obtain a modest current expense reduction, as the opposing parties have proposed, is obviously unfair. For that very reason, as explained by Mr. Hoch (Tr. 1850), extended lives of utility facilities should not be used to reduce depreciation expense until the investment necessary to accomplish the life extension has been reflected in the utility's rate base. This principle of depreciation has been approved and applied in a number of jurisdictions. For example, in Re Public Service Company of Indiana, Inc., 112 PUR4th 94, 148 (1990) the Indiana Commission held as follows:

[47/] The figure of $30 million was estimated based on capital addition costs of $205 million and a conservative fixed cost recovery rate of 15% for return, depreciation and taxes on return.

> [The Consumers Counsel witness] is, in essence, recommending that we accept such extended retirement dates (i.e., the benefits of the [life extension] program) without recognizing, in setting the depreciation rates for such units, the costs to achieve those extended life benefits. We reject such recommendations as being unreasonable and resulting in an improper matching of costs and benefits.

Accord Petition of Indiana Michigan Power Company, 1993 Ind. PUC LEXIS 460, (November 12, 1993); Application of Central Power & Light Co. For Authority To Change Rates, 1990 Tex. PUC LEXIS 233 (October 19, 1990) ("In calculating their depreciation rates, CPL and the Staff used the life to refurbishment or repowering, and eliminated the additions related to refurbishment or repowering. This approach should be adopted in this case.").

Significantly, this Commission has agreed with the depreciation principle discussed by Mr. Hoch and applied by the Indiana and Texas Commissions. Thus, in Pa. P.U.C. v. York Water Co., 78 Pa. P.U.C. 87, 109-110 (1993), the Commission refused to recognize, for depreciation purposes, extended lives of water storage basins until the investment needed to keep those basins in operation had actually been made. In so doing, the Commission accepted York's position on this issue, which was summarized in its Final Order, as follows:

> The Company further argues that since construction to extend the life of the basin has not yet begun, changing service life at this time will misstate depreciation expense and, will unfairly impose costs on future ratepayers. Thus, the benefits of any off-setting extension of lives that will be created by the actual construction should be

reflected at the same time as the construction is reflected in rates.

In summary, there is substantial evidence that the Company's older fossil-fired units cannot be operated economically beyond 2003 and, for that reason, life spans terminating on that date should be used to calculate annual depreciation expense in this case. Furthermore, even if it were assumed that the lives of the Company's older fossil-fired units would be extended beyond 2003, the longer lives should not be used to reduce depreciation accrual rates for ratemaking purposes until the capital additions necessary for life extension have been completed and recognized in rate base.

As previously indicated, witnesses on behalf of the OTS (Mr. Sivulich), OCA (Dr. Charles E. Johnson), PPLICA (Mr. Kollen) and DOD (Dr. Thomas Prisco) have contested the life spans for the Company's older fossil-fired units. None of these witnesses has attempted to make an affirmative presentation to demonstrate that the longer life spans they propose are feasible or economically justified. Instead, they have argued on a general and superficial basis that PP&L's proposed life spans are not supported by the evidence or are inconsistent with PP&L's earlier representations as to the probable service lives of its older fossil-fired units. These arguments are based on a misunderstanding of the relevant facts and should be rejected, as explained below.

Studies And Analyses. OCA witness Johnson contended that PP&L provided "no analyses of any kind to justify advancing the deactivation dates of Sunbury, Martins Creek and Holtwood." A similar assertion was made by PPLICA witness Kollen. Neither contention is correct. In his rebuttal testimony, Mr. Krall provided a detailed explanation of the economic analyses prepared by the Company (PP&L St. 5-R, pp. 6-9; PP&L Ex. DAK-5 and DAK-6). As Mr. Krall noted, those analyses showed that making a commitment to the substantial investment needed to comply with the CAAA -- which is essential if the Company's older fossil-fired units are to remain in operation beyond 2003 -- could not be justified as a prudent investment at this time.

Dr. Johnson, Mr. Kollen and Mr. Sivulich have also questioned the validity of the Company's analyses on the grounds that no retirements of its older fossil-fired units were shown in the Company's 1994 Annual Resource Planning Report ("ARPR") or in the associated Five-Year Upgrade Plan For Coal-Fired Generation. However, as Mr. Krall explained, by May 2, 1994, when the 1994 ARPR was submitted, the Company had not prepared detailed economic analyses reflecting the cost of Title I NO_x limitations and Title III air toxics reductions. Nonetheless, Titles I and III of the CAAA were mentioned in that document as a possible cause of capital additions that had not been factored into the resource planning process (Tr. 164-165).

Opposing parties have also tried to use the 1994 ARPR as evidence that PP&L's proposed changes in deactivation dates were made only to increase its revenue requirement for purposes of this case. Such an inference is totally unwarranted.[48] The economic analysis of continued operation based on capital additions needed for Title I and III compliance was driven by the fact that a major milestone in the CAAA implementation process was achieved on September 27, 1994 -- five months after the 1994 ARPR had been submitted. On that date, the member states of the Ozone Transport Commission, which includes Pennsylvania, executed a Memorandum Of Understanding On The Development Of A Regional Strategy Concerning The Control Of Stationary Source Nitrogen Oxide Emissions (Tr. 167-168). With the adoption of the Memorandum Of Understanding, it became clear that the magnitude of NO_x and air toxics reductions to be implemented would require major capital additions for emissions controls at the Company's older fossil-fired units (Tr. 1934). For that reason, post-September 1994 studies incorporated those capital additions in PP&L's resource planning analysis. This is clearly shown in the 1995 ARPR, submitted in May 1995, as Mr. Krall explained (PP&L St. 5-R, p. 9).

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[48] If increasing its revenue requirement were PP&L's motive, then it clearly would not have made changes in depreciable lives for other facilities, which more than offset the modest expense increase associated with the proposed shorter lives for its older fossil-fired units.

PP&L's Investment Decisions. Mr. Sivulich contended that PP&L's revised life span determinations are not consistent with its capital budgeting, which he claims shows "sizable capital additions to each of these units to continue their existence as long as economically possible." However, as Mr. Krall explained, Mr. Sivulich fundamentally misconstrued the nature of the capital additions that he had reviewed. All of the projects relating to the Company's older fossil-fired units were necessary to assure operation only through 2003, not over a longer term, as Mr. Sivulich had suggested (PP&L St. 5-R, p. 11). In fact, PP&L's 1995 ARPR explicitly states (Tr. 1937): "[N]o discretionary investment should be undertaken which requires operation beyond 2003 to recover its costs." PP&L has re-scoped a number of capital projects to eliminate all investment that would exceed the limits of the foregoing directive (Tr. 165, 170, 173-175; PP&L St. 5-R, p. 10).

Maximizing Life Spans/Industry Trends. In support of longer lives for the Company's older fossil-fired units, Mr. Sivulich also contended that "PP&L is maintaining all of its generating units to ensure maximum life spans." As Mr. Krall explained, that statement is not accurate and expresses an approach to life extension that is not consistent with prudent, least cost planning (PP&L St. 5-R, p. 14):

> Mr. Sivulich does not offer any basis for his assertion other than his apparent misunderstanding of the purpose of the [capital addition] projects set forth in his Schedule 4. In fact, PP&L is not

> maintaining any of its generating units to ensure MAXIMUM lives and I must reiterate that achieving maximum lives may <u>not</u> be in the best interest of PP&L's customers. As should be evident from the analyses I have provided and the investment strategies being pursued, it is PP&L's intent to achieve those lives which are cost effective and achieve the lowest revenue requirements.

Mr. Sivulich also asserted that longer lives, such as those he proposed, are consistent with "an industry trend of maintaining, upgrading, and extending the life spans of fossil fuel power plants as a less costly option to building new power production plants." The evidence adduced by Mr. Sivulich to support such a "trend" consisted of a report titled "Electric Power Outlook For Pennsylvania 1993-2013" prepared by the Commission's Bureau of Conservation, Economics and Energy Planning." As Mr. Krall pointed out, Mr. Sivulich's references to that document actually support the shorter life spans for the Company's older fossil-fired units proposed by PP&L (PP&L St. 5-R, p. 15):

> With regard to the "Electric Power Outlook" report, Mr. Sivulich quotes several paragraphs from pages 31 and 32 which note UGI Luzerne Division's current plants to retire Hunlock Unit 3 in 2004. Hunlock 3 is a steam station which was placed in service in 1959 and is fired by anthracite silt. Hunlock 3's boiler is virtually identical to the Sunbury boilers 1A, 1B, 2A and 2B (installed in 1949) which supply steam to Sunbury 1 and 2. The boiler at Holtwood 17 (installed in 1956) is a slightly larger version of the same design. Sunbury 1 and 2 and Holtwood burn the same fuel as Hunlock -- anthracite silt. PP&L engineers have discussed with UGI the problems of retrofitting this type of boiler for reduced NO_x emissions. UGI's tentatively planned retirement

> of a somewhat newer generating station is consistent with PP&L's finding of threats to the continued operation of Sunbury and Holtwood, in particular, and smaller, older generating units, in general, beyond the 2003 time frame.

For all of the reasons set forth above, the Company's proposed deactivation date of 2003 for its older fossil-fired units is reasonable, and its depreciation expense claim based thereon should be approved.

3. General Plant Amortization Accounting

The Company has proposed to adopt amortization accounting for those plant accounts in which it records certain general plant, e.g., office furniture, general tools and equipment. At September 30, 1995, these items will comprise less that 0.6% of PP&L's total investment in plant in service. The property recorded in these General Plant Accounts has a relatively low average cost per item, is subject to movement throughout the Company's system and requires an inordinate amount of administrative effort to maintain records by retirement units (PP&L St. 4, p. 15). Such recordkeeping detail is not required for amortization accounting for, for that reason, this Commission has approved amortization accounting of similar property for West Penn Power Company (Docket No. R-942986) and UGI Utilities, Inc. (Electric Division) (Docket No. R-932862) (Tr. 1848).

PP&L has used the same procedures for adopting amortization accounting in this case as were employed by West Penn and UGI. These procedures consist of the following:

(1) An amortization period is selected for each plant account. For example, for Account 391.2 (Furniture), PP&L has proposed a 20-year amortization period.

(2) All vintages of property that have an attained age greater than the proposed amortization period are deemed to be fully depreciated irrespective of the Company's actual capital recovery position. For example, all furniture older than 20 years would be deemed to be fully depreciated.

(3) For all other vintages of property, the annual amortization amount is calculated on a remaining life basis. That is, for each vintage of property, the attained age is subtracted from the amortization period and the remaining life is divided into the depreciated original cost of that vintage (see Ex. DSH-4). This is consistent with the Commission's approval of the remaining life method to depreciate utility plant in Pennsylvania (see Tr. 1846-47).

Only Dr. Johnson, on behalf of the OCA, has taken issue with the Company's claim for amortization accounting. While he purports to agree with the concept of amortizing the cost of small value items, Dr. Johnson disagrees with PP&L's implementation procedures and with the amortization periods it has selected. Dr. Johnson's recommendations would reduce the Company's amortization expense by $3.14 million (OCA Ex. CEJ-2, Sch. 2, p. 1 and Sch. 3, p. 2). For the reasons set forth below, Dr. Johnson's proposed revisions are erroneous and should be rejected.

depreciation) would be divided by the amortization period (OCA St. 5A, p. 10). This recommendation should be rejected. The deficiencies inherent in the whole-life depreciation method, i.e., the potential for over or under-recovery, are well known and formed the basis for the Commission's adoption of remaining life as the most appropriate capital recovery method for ratemaking purposes. See Pa. P.U.C. v. Western Pennsylvania Water Co., 59 Pa. P.U.C. 178, 214-222 (1985). Moreover, as previously discussed, both West Penn and UGI employed the remaining life method in their amortization accounting proposals, which the Commission approved.

Second, Dr. Johnson recommends that amortization accounting be implemented on a going-forward basis. That is, amortization would be used only for new vintages of property, not existing property (OCA St. 5A, p. 9: "Future vintages would be amortized and existing plant would continue to be depreciated. . ."). If adopted, this recommendation would defeat the purpose for converting to amortization accounting, namely, to reduce the time and expense of recordkeeping requirements necessary for depreciation calculations. Under the going-forward approach, PP&L would still have to maintain and update vintage retirement data for all existing general plant for the remainder of its depreciable life, e.g., 20 years in the case of office furniture. Applying amortization accounting to existing property on a remaining life basis, as PP&L has proposed, is reasonable, fair depreciable life, e.g., 20 years in the case of office furniture. Applying amortization accounting to existing property on a remaining life basis, as PP&L has proposed, is reasonable, fair to the Company and its customers and consistent with the approvals granted in West Penn and UGI, supra (Tr. 1848).

Amortization Periods. As previously indicated, Dr. Johnson proposed somewhat longer amortization periods for some of PP&L's General Plant Accounts. As Mr. Hoch explained, it is not clear from Dr. Johnson's testimony or exhibits what formed the basis for his recommendation (PP&L St. 4-R, pp. 11-12):

> While Dr. Johnson claims to rely upon the results of the 1980 [service life] study, his recommendations differ in several respects, presumably reflecting his judgment that a 15-year old study is not particularly relevant to determining appropriate current amortization periods. Dr. Johnson also refers to a retirement rate analysis that I prepared in 1994. This analysis applied actuarial techniques to calculate so-called "best fit" survivor curves. Mathematically determined survivor curves, while important, are but one input into the determination of appropriate service lives, as I will explain at a later point. Although Dr. Johnson refers to the results of the 1994 retirement rate analysis from time to time to support the amortization periods he proposes, in several significant respects he has departed drastically from the results of that study as well. For example, the 1994 retirement rate analysis indicated a "best fit" survivor curve for Account 395, Laboratory Equipment, based on an average service life of 19.2 years. Inexplicably, Dr. Johnson proposes a 40-year amortization period for that account. The Company has claimed a 15-year amortization period for Laboratory Equipment. Similarly, for General Computers, the 1994 retirement rate analysis indicated a "best fit" survivor curve based on an average service life of 8.5 years. As previously indicated, the "current

> life" for that account is five years. Nonetheless, Dr. Johnson accepted a ten-year amortization period.
>
> In summary, Dr. Johnson has proposed amortization periods that lack rational, consistent or understandable support. To the extent he has tried to offer support for his recommendations, it consists of indiscriminate use of stale or incomplete data.

As Mr. Hoch noted, he prepared a "retirement rate analysis" in 1994, which Dr. Johnson relied upon to try to support some of his extended amortization periods. However, as Mr. Hoch further explained, the results of such studies must be tempered with engineering judgment based on a practical understanding of how a utility actually intends to use its property (PP&LSt.4-R, pp. 12-13):

> An historical actuarial analysis is but one item on which a depreciation analyst relies to make engineering judgments about future life characteristics. A well-informed analyst will also examine other contributing factors and conditions that cause future life characteristics to differ from purely historical indications. These are precisely the kinds of factors that I explicitly considered in developing the amortization periods proposed for the General Property Accounts. Moreover, I provided detailed documentation concerning these factors to the OCA. Dr. Johnson unfairly characterizes my review as "discussions" with PP&L personnel about "how long furniture should last." In fact, a determination of management's philosophy of property utilization and property replacement is an essential aspect of service life determination, and I know of no depreciation expert that would disregard such inputs.

The amortization periods selected by Mr. Hoch are reasonable and properly reflect the factors affecting the remaining life of the Company's General Property Accounts. For the reasons set forth above, those amortization periods and the manner in which the Company proposes to implement amortization accounting should be approved.

VI. **TAXES**

A. Income Taxes

1. Consolidated Tax Savings

OCA witness Catlin proposes to adjust PP&L's claimed Federal income tax expense to reflect "consolidated tax savings" of $2,548,000 on a total Company basis, and $2,161,000 on a Pennsylvania jurisdictional basis (OCA St. 6, p. 38).[49] Specifically, Mr. Catlin, who calculated his adjustment using the "modified tax rate" method, explained his adjustment as follows (OCA St. 6, pp. 37-38):

> The calculation of my consolidated tax savings adjustment is presented on Schedule TSC-25. I am proposing to utilize the average consolidated tax savings for a three-year period in order to normalize the results and smooth out any fluctuations from year to year. The three years I have utilized for my calculation are the years ended December 31, 1993 and 1994 and the test year ended September 30, 1995. In developing my adjustment, I have excluded the taxable income of Interstate Energy Corporation (IEC) because IEC's net income fluctuates between gains and losses and because IEC is operated on a non-profit basis with the objective of having no return or profit. In addition, Pennsylvania Mines Corporation (PMC) had a tax loss of $21,616,200 in 1993 due to mine closing costs. I have treated this loss as abnormal and have utilized a normalized loss

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[49] PP&L and its affiliates file a consolidated federal income tax return. Companies filing a consolidated tax return can offset taxable income in one company with losses from another company, thereby reducing the consolidated tax liability of the group.

> for PMC in 1993 equal to the average for 1994 and 1995.

Mr. Catlin's recommended adjustment is patently inconsistent with relevant Commission precedent and should be rejected.

As a general matter, the Company believes that the allocation and imputation of tax loss deductions of affiliated companies to regulated utilities is completely inconsistent with sound ratemaking principles. For example, if an affiliate's investments and expenses are included in a determination of a utility's income tax allowance, they also should be reflected in the utility's revenue requirement (PP&L St. 3-R, pp. 14-15). More importantly, the imputation of tax loss deductions deprives nonutility affiliates of a valuable property right, particularly when utility customers do not bear any of the risks associated with nonregulated activities (PP&L St. 3-R, p. 15).

Its philosophical disagreement aside, however, PP&L recognizes that the Pennsylvania Appellate Courts have held that these so-called consolidated tax savings must be shared with the customers of the utility company even though they did not pay for any part of the investment which gave rise to the tax losses. See, e.g., Western Pennsylvania Water Co. v. Pa. P.U.C., 54 Pa. Cmwlth. 187, 422 A.2d 906 (1980). However, even applying this standard, Mr. Catlin's proposed adjustment lacks merit and should be rejected for three reasons.

First, any consolidated tax savings adjustment should reflect a reasonable estimate of tax losses that will occur during the period in which new rates will be in effect. For this reason, the Commission and the Courts have repeatedly held that a consolidated tax savings adjustment must be based on data which is representative of conditions that are likely to prevail in the future.

The earliest reported application by the Commission of a consolidated tax savings adjustment is Pa. P.U.C. v. The Manufacturers Light & Heat Co., 33 Pa. P.U.C. 669, 727 (1956). In that case, Manufacturers filed a consolidated tax return with its parent, Columbia Gas System and other affiliates; the parent provided debt interest expense deductions and certain affiliates had tax losses which reduced the amount that would have been payable by the gain entities (including Manufacturers). Significantly, the Commission declined to consider temporary effects that were not ongoing, e.g., the tax losses of the operating affiliates. The Commission stated:

> The largest tax loss company is in process of merging with an affiliate, the smallest-loss company is a non-utility company and the amount of the loss of the other tax-loss company is non-recurring in amount. In these proceedings, as in respondent's prior rate case, we agree with respondent that the 1954 consolidated tax savings should be adjusted to eliminate the tax-loss companies . . . (33 Pa. P.U.C. at 727-727) (emphasis supplied)

The Commission's ruling was affirmed on appeal sub nom. City of Pittsburgh v. Pa. P.U.C., 182 Pa. Super. 551, 128 A.2d 372 (1957).

In the second case involving consolidated tax savings, Pa. P.U.C. v. Riverton Consol. Water Co., 34 Pa. P.U.C. 248, 292 (1956), a water utility filed its taxes on a consolidated basis with its parent and other affiliates, including 15 tax-loss companies. The Commission adjusted "stand-alone" taxes for consolidated savings, but only after eliminating the impact of loss affiliates which could anticipate rate increases or other events that would place them in a tax gain position. On appeal by the utility, this consolidated tax savings adjustment was also affirmed. Riverton Consol. Water Co. v. Pa. P.U.C., 186 Pa. Super. 1, 19-21, 140 A.2d 114, 123-24 (1958).

More recently, in Pa. P.U.C. v. Pennsylvania Water Co. - Sayre Division, Docket No. R-891473 (August 31, 1990), the Commission reaffirmed its position that the ratemaking process is prospective in nature. Thus, in evaluating a proposed consolidated tax savings adjustment in that case, the Commission observed: ". . . what is sought in this calculation is the level of income tax which will be representative of PWC's taxes during the period of time the new rates will be in effect" (Order, p. 7). See also Pa. P.U.C. v. Nat'l Fuel Gas Distribution Corp., 62 Pa. P.U.C. 407, 426 (1986)(proposed consolidated tax savings adjustment rejected based on projections that a chronic loss company would have taxable income during the period new rates would be in effect).

Applying these principles, it becomes clear that Mr. Catlin's recommendation must be rejected because it fails to reflect a reasonable estimate of the tax losses that will occur during the period when new rates will be in effect. 86% of Mr. Catlin's proposed adjustment on a total Company basis and 86% of his adjustment on a Pennsylvania jurisdictional basis relates to historic tax losses for Pennsylvania Mines Corporation ("PMC") and Rushton Mining Company ("Rushton"). These companies are no longer in operation and obviously will not generate any tax losses in the future. The tax losses associated with these companies are non-recurring and should not be considered in establishing rates.

Second, PMC and Rushton were never intended to operate at a profit or loss. Any income or loss shown in a particular year is due solely to temporary tax/book timing differences which reverse in the succeeding year, and losses attributable to these two companies therefore should not be reflected in consolidated tax savings adjustments (PP&L St. 3-R, p. 16). As Mr. Bernini explained (Id.):

> [W]hen these mines were operating, they shipped all their coal to PP&L. PP&L paid these companies their cost of producing the coal so that, on a book basis, the coal mines made no profit and incurred no loss. Any taxable income and losses occurred principally due to the differences in timing

> when certain expenses were recorded on the books but were not currently deductible for tax purposes. As a result of such timing differences, these companies would show small taxable income in some years and small taxable losses in other years. Timing differences of this type are not recurring losses of the type for which consolidated tax savings adjustments should be made.

As noted above, Mr. Catlin specifically excluded from his adjustment taxable income attributable to Interstate Energy Corporation because it is operated on a non-profit basis. To be consistent, Mr. Catlin should have excluded taxable losses of PMC and Rushton as well since both companies are also operated on a non-profit basis.

Third, PP&L's customers have already received the benefit of the tax losses generated by PMC and Rushton through lower ECR charges. Expenses incurred when these companies were in operation were recorded on PP&L's books. These costs, however, may not have been tax deductible until actually paid. Anticipating these future tax deductions, the mining companies would credit deferred income taxes and establish a deferred tax asset. This deferred credit for income taxes would be reflected as a reduction in the cost of coal to PP&L, which, in turn, was flowed through to PP&L's customers through the ECR. In other words, <u>the tax savings identified by Mr. Catlin have already been passed through to PP&L's customers in the cost of fuel</u>. Mr. Catlin's proposed adjustment improperly allows customers to benefit twice from the same cost savings and therefore should be rejected (PP&L St. 3-R, pp. 16-17).

For the reasons set forth above, Mr. Catlin's adjustment should be rejected.

2. Adjustments To Taxable Income

PP&L has included a number of adjustments to its claim for test year income tax expense (PP&L Ex. 1 Future - Revised, Sch. D-19). The OCA proposes three additional adjustments. Specifically, Mr. Catlin seeks to eliminate: (1) $9,690,000 associated with ECR over-collections; (2) $2,724,000 related to nuclear refueling costs; and (3) the amount by which test year uncollectibles expense exceeds projected bad debt write-offs (OCA St. 6, pp. 33-34). Collectively, Mr. Catlin's adjustments reduce income taxes and increase net income by $6,058,000 on a total Company basis, and $5,810,000 on a Pennsylvania jurisdictional basis (OCA St. 6, p. 35). The OCA's adjustments lack merit and should be rejected.

Mr. Catlin's recommendations are inappropriate efforts to "cherry pick" individual items in an effort to arbitrarily and unfairly whittle away at the Company's rate request. As explained by Mr. Bernini, the total level of income tax expense reflected in PP&L's filing represents a reasonable and normal amount for ratemaking purposes (PP&L St. 3-R, p. 18).

Microscopic scrutiny of each line item included in the Company's claimed level of income tax expense will undoubtedly reveal fluctuations in <u>individual</u> items over time. What Mr.

Catlin fails to recognize, however, is that these individual items will fluctuate both up <u>and</u> down. Mr. Catlin focuses solely on the "down" and ignores the "up".

Mr. Bernini illustrated this point with the following example involving a tax/book timing difference in the treatment power plant inventory (PP&L St. 3-R, p. 19):

> Exhibit Future 1, D-19, p. 1, shows a <u>reduction</u> to taxable income of $5,012,000 for "power plant inventory - tax accounting change." This tax/book difference is caused by the fact that the change in inventory method was amortized over five years for book purposes but over six years for tax purposes. The Company began this amortization in 1991. Therefore, the amortization on the Company's books will expire in 1995, and the amortization for tax purposes will expire in 1996. Thus, in 1996, the initial period new rates are in effect, the negative $5,012,000 will become a positive $17 million. Thereafter, the number will go to zero because both amortization will be complete. To quote Mr. Catlin, the $5,012,000 deduction from taxable income is a "short-term, temporary timing difference which should not be included in the calculation of the income taxes used to set rates."

On surrebuttal, Mr. Catlin agreed that his adjustment should be reduced to offset the effect of tax/book timing difference for power plant inventory (OCA St. 6A, p. 14). The Company urges the Commission to go further and reject Mr. Catlin's adjustment in its entirety.

Finally, the bad debt portion of Mr. Catlin's adjustment is in error for a further reason. As explained by Mr. Bernini, Mr.

Catlin bases this adjustment on his assumption that the Company's proposed uncollectibles expense is representative of its actual bad debt write-offs. This is simply not the case. PP&L's uncollectible accounts expense claim is based on the accrual to its uncollectible reserve, not the actual level of bad debt write-offs (PP&L St. 3-R, p. 20). Mr. Catlin's adjustment is based on an incorrect assumption and therefore should be rejected.

In sum, PP&L's total claimed level of income tax expense is reasonable and should be allowed. Mr. Catlin's arbitrary, individual adjustments are completely inappropriate.

B. Gross Receipts Tax

The OCA contends that PP&L has incorrectly claimed gross receipts tax expense in connection with revenues that will not be collected (OCA St. 6, p. 33). Mr. Catlin therefore reduced gross receipts taxes by $745,000 and increased net income by $431,000 (Id.).

Mr. Catlin's proposed adjustment is wholly inappropriate and should be rejected. As explained by Mr. Bernini, Mr. Catlin again seeks to reduce the Company's rate request below reasonable levels (PP&L St. 3-R, pp. 17-18):

> The revenues claimed by the Company are the level of revenues required for the Company to earn its requested rate of return. In the real world, the Company will not collect all of these revenues because a portion of these

> revenues will prove to be uncollectible. As a result, all else equal, the Company will not earn its allowed return. Mr. Catlin seizes upon this unfortunate fact of life to reduce the Company's GRT claim, arguing that the Company will not have to pay GRT on revenues it does not collect. This is inappropriate in my view. It is bad enough that the Company will not actually earn its allowed return. Mr. Catlin, however, would exacerbate this attrition by reducing the Company's tax expense to reflect this revenue shortfall. . . . It is unfortunately true that the Company will not collect all of the revenues approved by the Commission. It would be fundamentally unfair to reflect this attrition in the calculation of GRT for ratemaking purposes. It would simply further assure that the Company does not earn its allowed return.

In surrebuttal, Mr. Catlin contended that the Company is fully compensated for the effect of uncollectible accounts through an expense allowance (OCA St. 6A, p. 13). Mr. Catlin is in error for two reasons. First, the issue here is revenues, not expenses. Mr. Catlin mixes apples and oranges. <u>All</u> of the revenues requested are required to permit the Company to earn its requested return. The fact that the Company will not actually collect all of this revenue and will not actually earn its requested return provides <u>no</u> basis for further reducing the Company's rates by disallowing GRT on revenues which will not be collected. Second, the Company, in order to be conservative and to keep the total amount of its requested increase reasonable, did not claim any additional uncollectible accounts expense associated with the revenue increase requested in this proceeding. This $1.6 million in unclaimed costs more than offsets Mr. Catlin's entire adjustment.

PP&L is not aware of any proceeding in which the Commission has approved such an adjustment. The OCA's adjustment is inappropriate and should be rejected.

VII. FAIR RATE OF RETURN

As a public utility whose facilities and assets have been dedicated to the service of the general public, the Company is entitled to an opportunity to earn a fair rate of return on its investment. The standards to be used by the Commission in determining a fair rate of return are well-established, having been set forth by the United States Supreme Court in Bluefield Waterworks and Imp. Co. v. PSC of West Virginia, 262 U.S. 679 (1923), more than seven decades ago:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility of its property in violation of the Fourteenth Amendment. (262 U.S. at 690)
>
> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. (262 U.S. at 693)

These principles have been adopted and applied by the Appellate Courts of Pennsylvania in numerous cases. See, e.g., Riverton Consolidated Water Co. v. Pa. P.U.C., 186 Pa. Super. 1, 140 A.2d 114 (1958); Pittsburgh v. Pa. P.U.C., 182 Pa. Super. 376, 126 A.2d 777 (1956); Lower Paxton Twp. v. Pa. P.U.C., 13 Pa. Cmwlth. 135, 317 A.2d 917 (1974).

The return allowed to investors must be commensurate with the risk assumed, as the Supreme Court has stated in three landmark opinions. Bluefield, supra, requires that the rate of return reflect:

> A return on the value of the [utility's] property which it employs for the convenience of the public equal to that generally being made at the same time on investments in other business undertakings which are attended by corresponding risks and uncertainties. (262 U.S. at 692)

Twenty-one years later, the Supreme Court reiterated that standard in Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944), as follows:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. (320 U.S. at 603)

More recently, in reaffirming Hope, the Supreme Court, in Duquesne Light Co. v. Barasch, 109 S.Ct. 609 (1989), observed that "[o]ne of the elements always relevant to setting the rate under Hope is the return investors expect given the risk of the enterprise."

The determination of a fair rate of return thus requires the review of many factors, including: (1) the earnings which are necessary to assure confidence in the financial integrity of the Company and to maintain its credit standings; (2) the need to pay dividends and interest; and (3) the amount of the investment, the size and nature of the utility, its business and financial risks, and the circumstances attending its origin, development and operation. Pa. P.U.C. v. Pennsylvania Gas and Water Co. - Water Division, 19 Pa. Cmwlth. 214, 233, 341 A.2d 239 (1975); Lower Paxton Twp., supra. Moreover, the Commission's findings must be based upon substantial and competent evidence on the record before it, not upon speculation or hypothesis. Ohio Bell Telephone Co. v. Pub. Util. Comm. of Ohio, 301 U.S. 292 (1937); United States Steel Corp. v. Pa. P.U.C., 37 Pa. Cmwlth. 195, 390 A.2d 849 (1978); Octoraro Water Co. v. Pa. P.U.C., 38 Pa. Cmwlth. 83, 391 A.2d 1129 (1978).

In this proceeding, two witnesses appeared on behalf of the Company in the area of fair rate of return. Mr. Ronald E. Hill, Senior Vice President-Financial of PP&L, described the Company's current and near-term future capital attraction needs. In addition, Mr. Paul R. Moul, Managing Consultant of Moul & Associates, testified in support of PP&L's specific fair rate of return requirement. Mr. Moul has appeared before this Commission on numerous occasions in the past. His credentials and experience are well known and his recommendations deserve careful consideration.[50]

The following table summarizes the Company's position as to the required fair rate of return in this proceeding. The capital structure ratios and cost of long-term debt and preferred stock are the estimated levels at September 30, 1995, the end of the future test year in this case. PP&L's claimed cost of common equity is 13% and is clearly reasonable in light of the analysis performed by Mr. Moul.

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.53%	7.97%	3.71%
Preferred Stock	7.59	7.31	0.55
Common Equity	45.88	13.00	5.96
Total	100.00%		10.22%

A. Capital Structure

In developing his recommended fair rate of return, Mr. Moul employed the Company's anticipated capital structure ratios at the end of the future test year: 46.53% long-term debt, 7.59% preferred stock and 45.88% common equity (PP&L St. 12, p. 2). This approach is identical to that approved by the Commission in any number of recent rate proceedings. See, e.g., Pa. P.U.C. v. Pennsylvania-American Water Co., 79 Pa. P.U.C. 25, 80 (1993);

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[50] A description of Mr. Moul's education, professional experience and qualifications as an expert is set forth in PP&L Statement 12, Appendix A.

Pa. P.U.C. v. Pennsylvania-American Water Co., Docket No. R-901652 (December 14, 1990) (Order, p. 105).

Two issues were raised by the parties concerning the Company's proposed capital structure. PPLICA witness Baudino proposed to set the Company's capital structure ratios based on conditions at the end of the historic test year, rather than the future test year (PPLICA St. 1, p. 37). OCA witness Kahal generally utilized the Company's future test year capital structure ratios, but questioned a proposed new issuance of common equity and refused to adjust the Company's capital structure ratios to reflect the effect of premiums paid to reacquire high cost long-term debt and preferred stock (OCA St. 1, p. 13). For the reasons set forth below, each of these adjustments should be rejected.

1. The OCA And PPLICA Adjustments To The Company's Future Test Year Capital Structure Should Be Rejected

As noted previously, PPLICA's witness Baudino proposed to rely on historic test year data to establish the Company's capital structure ratios. The Company's filing in this case is based upon a future test year ending September 30, 1995. All elements of the ratemaking formula, i.e., revenues, expenses, rate base and return, have been annualized and normalized to reflect anticipated conditions at the end of the future test year (PP&L St. 3, pp. 3-4; Ex. Future 1 - Revised). There is absolutely no basis upon which to reject the future test year data for a single item, i.e., capital structure ratios. Mr. Baudino's proposal, if adopted, would create a fundamental mismatch between capital structure and all other elements of the ratemaking formula.[51]

Moreover, the principal reason given by Mr. Baudino for utilizing historic test year data was the fact that, in his view, PP&L had not adequately explained and defended its future test year financing plans. In his rebuttal testimony (PP&L St. 12-R, pp. 9-11), Mr. Moul fully addressed Mr. Baudino's "concerns" and demonstrated the reasonableness of the Company's future test year end capital ratios. Mr. Baudino offered no response and presumably was satisfied with Mr. Moul's explanation.

OCA witness Kahal generally accepts the Company's future test year capital structure, but questioned a proposed issuance of new common equity because the new equity had not yet been sold (OCA St. 1, p. 13). This adjustment should be rejected. Most of the elements of a rate case are based, at least in part, on projections, including revenues, expenses, rate base, proposed capital structure and capital costs. These projections are based upon the best information available at the time the case is decided. The use of projections is a standard part of ratemaking. It would be unfair and unreasonable to abandon this

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[51] In addition, it should be noted that Mr. Baudino has proposed to use PP&L's <u>future</u> test year end embedded cost rates. Those rates are, of course, a function of the very future test year financings that Mr. Baudino would ignore for capital structure purposes.

standard ratemaking practice for one issue, i.e., the Company's proposed issuance of new common equity.

The best available evidence demonstrates that the Company will issue new common equity in the near future. First, the issuance of new common equity is necessary and appropriate. The Company's current equity ratio is too low compared to other electric utilities (PP&L St. 12-R, pp. 11-12). Indeed, the bond rating agencies have specifically criticized the Company's equity ratio as being too low (PP&L St. 12-R, p. 9). As explained by Mr. Moul, the Company must issue additional common equity to improve its common equity ratio and avoid a further downgrading of its bonds (PP&L St. 12-R, p. 12):

> Additional equity is necessary to respond to the more stringent financial criteria now required by the bond rating agencies. Moreover, the rating agencies have expressed a concern over the Company's high debt use in the past. The Company's financing plan is required to alleviate those concerns and represents a prudent course of action to help prevent further bond downgradings.

Second, as noted by Mr. Moul, the new equity issuance is part of a two-step financing plan. The first step in this plan involves the repurchase of high-cost debt. This repurchase is virtually complete. The second step of the financing plan, the issuance of new common equity, is now ready to move forward (PP&L St. 12-R, pp. 11-12). In fact, the Company has already undertaken a number of specific steps to issue the new common equity, including Board of Directors authorization, selection of lead underwriters and preparation of the SEC Registration Statement (PP&L St. 12-R, p. 11).

While the exact timing of the common equity issuance is not certain, it is clear that the Company has a definite need to issue new equity, has a specific plan to do so and has taken specific steps to implement that plan. The Company has clearly met its burden of proving the reasonableness of its projection on this issue based upon the most recent available information.

2. Ratemaking Treatment Of Reacquisition Premiums

As explained by Mr. Hill, the Company has undertaken an aggressive program to refinance high-cost debt and preferred stock. This program has dramatically lowered PP&L's cost of capital and is reflected in lower senior capital cost rates in this proceeding (PP&L St. 1, p. 5).[52/]

The Commission has recognized that refinancing high-cost debt produces direct benefits to ratepayers and should be encouraged (PP&L St. 12, pp. 29-30). See Pa. P.U.C. v. National Fuel Gas Distribution Corp., 73 Pa. P.U.C. 552, 607 (1990). The Commission also has held that a utility should be allowed to fully recover all costs associated with the reacquisition of high-cost debt and that the utility's capital structure and

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[52/] For example, PP&L's claimed cost of long-term debt in this case is 7.97%, as compared to 11.27% in the Company's last rate case. Compare PP&L St. 12, p. 2, with Pa. P.U.C. v. Pennsylvania Power & Light Co., 67 PUR4th 30, 80 (1985).

capital costs should not be adversely affected by such reacquisitions. Id. As ALJ Cohen stated in his Recommended Decision (p. 154) in the 1990 NFG case:

> In the early 1980s, the Commission sent letters to NFGDC and other utilities, encouraging the utilities to reacquire high cost debt and replace it with lower cost of debt for the purpose of reducing the overall embedded cost of debt to be charged to ratepayers. The letter from the Commission to NFGDC is dated July 24, 1986. The letter provides as follows:
>
>> The Commission is aware that current bond market conditions provide opportunities for utilities to refund outstanding issues of high coupon debt. The Commission encourages such refunding if the utility can demonstrate that it is in the public interest. The Commission will favorably consider ratemaking treatment which allows recovery of and a return on the call or tender premium which must be paid to accomplish such transactions if there is a showing that the transactions were prudently undertaken and result in significant and measurable savings to ratepayers (Exh. No. 212-A, Sch. 1).

In order to reacquire high-cost debt and preferred stock, the Company, in most instances, had to pay a premium to existing bondholders and preferred stockholders (PP&L St. 12, p. 28). The Company followed standard Commission practice in this proceeding and adjusted both its capital cost rates and capital structure to reflect the effect of these premiums.

OCA witness Kahal recognizes and accepts the change in the cost of debt and preferred stock associated with these refinancings, but opposes any adjustment to capital structure

(OCA St. 1, p. 14). Mr. Kahal's analysis is inconsistent and flawed, and, if accepted, would create a fundamental mismatch between the establishment of capital cost rates and capital structure.

The premiums paid by the Company to reacquire high-cost debt and preferred stock were financed with newly issued long-term debt.[53] The issuance of additional long-term debt to finance the premiums increased the amount of long-term debt outstanding and obviously affected both the cost of long-term debt <u>and</u> the Company's capital structure. For Mr. Kahal to recognize one effect of these refinancings (cost of capital effect) and not the other (capital structure effect) is clearly inconsistent and should be rejected.

In rebuttal, Mr. Moul demonstrated that Mr. Kahal's approach would severely penalize the Company for having reacquired high-cost debt and preferred stock (PP&L St. 12-R, p. 8 and Sch. 2). As that analysis shows, failure to adjust the capital structure would artificially increase long-term debt and decrease common equity. This is particularly troublesome for PP&L, whose common equity ratio is already too low and has been specially criticized by the rating agencies (PP&L St. 12, p. 12).

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[53] Mr. Kahal assumed that the premiums were paid out of general Company funds and therefore did not affect the Company's capital structure (OCA St. 1A, p. 7). This is not the case. Mr. Moul specifically testified that the premiums were paid out of the proceeds of new long-term debt (Tr. 1834-35).

Finally, and as noted above, the same adjustment proposed by Mr. Kahal has been repeatedly rejected in a series of National Fuel Gas rate cases. Pa. P.U.C. v. National Fuel Gas Distribution Corp., 62 Pa. P.U.C. 407, 435 (1986); Pa. P.U.C. v. Nattional Fuel Gas Distribution Corp., 67 Pa. P.U.C. 264, 324-26 (1988). As the Commission has stated:

> We conclude that NFGD has properly accounted for these unamortized refinancing premium costs. The OCA's proposal to include the unamortized refinancing premium costs in the principal amount of debt used in computing the effective debt cost rate is incorrect since the premiums were paid to former debenture owners and therefore are no longer available to the Company. We adopt the recommendation of the ALJ and deny the OCA Exceptions." 67 Pa.P.U.C. at 326.
>
> The OCA would also remove $5 million of tender and call premiums from NFGD's long-term debt to compute its long-term debt ratio and increase its long-term debt cost rate. OCA maintains that NFGD cannot both recover its call and tender premiums through amortization and simultaneously earn a return on its unamortized expense balance. The OCA further maintains that NFGD should only be allowed an amortization of these call and tender premiums (R.D. at 150).
>
> We agree with the Company that our letter to NFGD dated July 24, 1986, makes it clear that the Commission intended to allow full recovery of the Company's expenses and a return on such expenses in order to provide an incentive to reduce the embedded cost of debt associates with prudent refinancing to high cost debt. We, therefore, deny the OCA's exceptions to the Company's procedure to recover the costs associated with refinancing high cost debt. Accordingly, we adopt the ALJ's recommendation on the proper capital structure to be allowed NFGD in this proceeding.

Mr. Kahal's adjustment is patently inconsistent with Commission precedent, ignores reality and would create a fundamental mismatch between capital structure and senior capital cost rates. It therefore should be rejected.

In addition to failing to adjust the Company's capital structure, the OCA, through the testimony of Mr. Catlin, also proposes a $40 million reduction to the Company's rate base to reflect deferred taxes associated with the reacquisition premiums (OCA St. 6, p. 6). As explained by Mr. Moul, this adjustment also should be rejected. First, there is no basis for any rate base adjustment because the Company has not sought to include the premiums in rate base. If any adjustment were to be made, it should be made to capital structure ratios, not to rate base (PP&L St. 12-R1, pp. 1-4). On surrebuttal, Mr. Kahal agreed (OCA St. 1B, p. 9).

The reacquisition premiums were tax deductible at the time they were paid. The issue is how those tax savings should be credited to customers. Under the Company's method, the tax savings generated by the reacquisition premiums will be flowed through to customers as those customers pay the underlying cost of the premium (PP&L St. 12-R1, pp. 1-2). The Company financed the premiums initially and will recover them from ratepayers over the life of the new debt. Since customers will pay the cost of the premium over the life of the debt, they should receive the associated tax savings over the same period. Id. To do otherwise would create a mismatch between the tax savings and the underlying cost which generated the tax savings. Research has found no case in which the Commission has made any adjustment of this type. Mr. Kahal's unprecedented adjustment should be rejected.

B. Embedded Cost Rates Of Long-Term Debt And Preferred Stock

The Company's proposed cost rates for long-term debt and preferred stock are 7.97% and 7.31%, respectively (PP&L St. 12, pp. 31-32). As in the case of Mr. Moul's recommended capital structure ratios, these figures are based on the Company's anticipated cost of debt and preferred stock at September 30, 1995, the end of the future test year in this case. It is PP&L's understanding that these embedded cost rates are not in dispute.

C. Common Equity Cost Rate

To attract capital of any kind on reasonable terms, a utility must first demonstrate the ability to achieve an adequate return on the equity already invested in the enterprise. For that reason, determination of the appropriate common equity cost allowance is one of the most important issues in every rate case.

In the discussion that follows, the Company will examine in detail the equity cost recommendations of the opposing parties. However, that detailed review of the evidence presented should not obscure the fundamental goal of this proceeding. That objective, to which <u>all</u> parties presumably are committed, is the establishment of rates sufficient to enable the Company to maintain its financial integrity, attract capital on reasonable terms and provide quality service to its customers.

1. <u>Overview</u>

Any reasoned determination of the common equity cost rate in this proceeding must reflect the increased risk facing electric utilities in general and PP&L in particular. The emergence of increasing competition in the electric utility industry will fundamentally change the structure of that industry and its risk. Competition from cogenerators, independent power producers, customer self-generation and wholesale competition from other electric utilities under the Energy Policy Act of 1992 have created a new playing field for electric utilities in the 1990s. As explained by Mr. Moul (PP&L St. 12, pp. 9-10):

> Today, electric utilities are faced with meaningful changes in fundamentals, while cost of service pricing continues to dominate their business profile. Aside from their traditional responsibility to supply adequate capacity to meet forecast loads (in a more uncertain market), and to comply with increasingly stringent environmental standards, additional competitive risks are now evolving in a new era for electric utilities. These risks include competition from alternative energy sources and competition from other utilities and non-utilities. Sometimes this situation is referred to as the risk or self generation and/or risk of bypass. With the evolution of cogeneration as an alternative source of energy, as well as energy available from independent power producers, the loss of revenues from existing customers which obtain energy from alternative sources is particularly onerous as compared with a new electric user providing its own generating capacity. When customers engage in either self-generation or bypass of a utility's integrated system, the electric utility is faced

> with the prospect of losses occasioned by stranded investment and unrecovered costs. With increased emphasis on market-determined prices and competition in the electric generation market and the trend toward open access of the transmission network (e.g., the National Energy Policy Act of 1992), an entirely new dimension has been opened in the electric utility business. However, pricing policies of public utilities are restrained by regulation, while other non-regulated firms have greater latitude in adjusting their prices and responding to changing market conditions. A pricing structure restricted by regulation diminishes management's ability to adjust its business strategy quickly to changing market conditions to respond to broadening competition. Hence, partial deregulation of electric utilities provides significant downside risk due to loss of revenues, but provides little upside potential due to the limitations placed on returns by regulators.

This new level of competition has created grave uncertainty within the industry and has dramatically increased the risk of investing in electric utilities. The impact of these increased risk factors has been clearly demonstrated in the recent financial performance and changing investor perception of the electric utility industry. Since October 30, 1994, the S&P Public Utilities have lost approximately 19% of their market value, with the electric utilities within that group losing over 25% of their market value (PP&L St. 12, p. 11).

The bond rating agencies also have reacted to this increased risk by establishing a new matrix for measuring the financial strength of electric utilities. Specifically, S&P has categorized each electric utility according to its assessment of its business position as above average, average or below average.

Factors considered by S&P in making this determination are markets and service area economy, competitive position, fuel and power supply, operations, asset concentration, regulation and management. Id. at 12.

These industry-wide risk factors will have a particularly severe effect on PP&L. The Company has a significant number of industrial customers, who are more likely and better able to capitalize on new competitive options than other customers (PP&L St. 12, p. 14). The Company also has a relatively large amount of cogeneration on its system at a relatively high cost as compared to current market rates. Id. This will impose further competitive pressure on the Company.

PP&L also faces further important risk factors, including aggressive competition from gas utilities for the space heating market, a large construction program and major expenditures to comply with the Clean Air Act Amendments of 1990 (PP&L St. 12, pp. 14-18). Moreover, as noted above, the Company has a relatively low common equity ratio and above average financial risk.

The combination of these increased business and financial risks resulted in the downgrading of PP&L's bonds by S&P from A to A- in July 1994. Supportive rate regulation is always an important factor in a utility's financial health (PP&L St. 12, p. 10). The outcome of this rate case is particularly important, if the Company is to preserve its ability to attract capital on reasonable terms and provide reliable service to customers.

In recent cases the Commission has awarded water utilities common equity allowances of approximately 11%. See, e.g., Pa. P.U.C. v. Roaring Creek Water Co., Docket No. R-943177 (May 31, 1995) (Order, p. 49). Water utilities are clearly subject to far less risk than electric utilities. The electric utility cost of common equity therefore must be substantially higher than 11.0%.

Similarly, in the most recent electric rate proceeding the Commission awarded West Penn Power Company a common equity cost allowance of 11.5%. Pa. P.U.C. v. West Penn Power Co., Docket No. R-00942986, 1994 Pa. PUC LEXIS 144, *147 (December 29, 1994). West Penn has an A+ bond rating as compared to PP&L's A- bond rating (PP&L St. 12-R, p. 4). In addition, West Penn has lower rates than PP&L and no nuclear investment exposure.

Based on these decisions, it is clear that PP&L must have an equity cost allowance in the 12-13% range in order to have any meaningful possibility of attracting capital on reasonable terms. A lower return would simply drive investors to other alternatives. No rational investor would invest in PP&L at a return of less than 12%, when that investor can receive 11-11.5% in much safer investments.

Despite this clear evidence, the opposing parties in this proceeding have proposed equity cost rate allowances ranging from

10.65% to 11.5%. These allowances are clearly inadequate given recent Commission equity cost rate determinations and the increased risks facing the electric utility industry. If adopted, they would seriously harm the Company's financial condition and fail to provide it with any opportunity to earn a fair rate of return.

The opposing parties undoubtedly will focus heavily in their briefs on the decline in interest rates at or about the time of the close of the record in this proceeding. The Company urges the Commission not to be misled by this smokescreen. The equity cost rate determination in this case is applicable to the time period new rates set in this case will be in effect and should not be unduly influenced by temporary short-term variations in interest rates. Interest rates are currently highly volatile and move up and down rapidly in response to a variety of economic and market conditions. The fundamental risk factors affecting electric utilities, however, are increasing and will continue to increase. These heightened risk factors more than offset any temporary short-term decline in money costs.

Finally, the Commission should take into account the quality of management in its fair rate of return analysis. As explained at length in Mr. Hill's direct testimony, the Company has undertaken a number of important initiatives, cost reduction efforts and productivity improvements. As explained by Mr. Hill (PP&L St. 1, pp. 4-6) (emphasis added):

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

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

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

On the revenue side, the Company has made a major commitment to economic development to retain existing industry and to attract new businesses to its service territory. In addition to revenue enhancement, these economic development efforts have produced thousands of new jobs in the Company's service territory. While increasing sales, the Company also had remained committed to

> conservation, load management and demand-side management (DSM) programs designed to promote more efficient and cost effective usage by its customers. . . .
>
> Finally, the Company has maintained and expanded its commitment to those customers who cannot afford to pay their electric bills. As explained by Mr. Bujnowski's testimony, the Company has been and continues to be a leader in this important area and is proposing a number of important new social programs in this case.

These initiatives have permitted PP&L to avoid filing for a base rate increase for over ten years. As a result of these efforts, the Company's rates today are about the same as they were in 1985, despite an increase in the CPI of more than 30% (PP&L St. 1, p. 4). In other words, PP&L's rates have actually declined in real terms. This is a remarkable accomplishment, particularly given the increasing risk factors and revenue erosion associated with increased competition in the electric utility industry.

Over and above the fundamental risk factors in this case, the Commission should recognize the Company for its efforts in maintaining rate stability to customers over the past ten years and adopt an equity cost rate allowance at the upper end of the zone of reasonableness.

2. PP&L's Equity Cost Recommendation

As noted previously, PP&L has requested that it be permitted an equity cost opportunity rate of 13%. The Company believes this figure is not only reasonable, but may be conservative in light of the fundamental changes in the electric utility industry and the specific impact of those changes on PP&L. For that and the other reasons set forth below, the Company's proposed equity allowance should be approved.

a. <u>Methodologies Utilized</u>

For the time period relevant to this case, PP&L's common stock was publicly traded and therefore provides the best and most direct evidence of PP&L's equity cost rate requirements. At its annual meeting in May 1995, PP&L's shareholders approved the creation of a holding company structure. Under this structure, the stock of the holding company, PP&L Resources, is publicly traded, and all of PP&L's stock is now held by PP&L Resources. However, the operations of the holding company are and will continue to be dominated by PP&L's electric operations which continue to provide the best and most direct measure of the Company's cost of equity (PP&L St. 12, p. 3).

As a check on the reasonableness of his primary results, however, Mr. Moul also relied on the results of a Barometer Group of eight electric utilities with risk characteristics similar to those of the Company. <u>Id.</u> These eight companies were selected based on a variety of criteria to provide a group reasonably comparable in risk to PP&L (PP&L St. 12, p. 19). On balance, PP&L is somewhat more risky than the Barometer Group due to its lower bond rating (A- versus average rating of A for the Barometer Group) and its lower common equity ratio. <u>Id.</u> at 26.

For that reason, PP&L's equity cost rate should be in the upper range of the Barometer Group cost of capital.

The cost of common equity does not lend itself to precise mathematical computations; rather, it requires the exercise of informed judgment based on a careful evaluation of all the available data. Consequently, Mr. Moul did not rely solely upon a single cost of equity technique in developing his recommendation, but instead took into account the results of a variety of approaches, including DCF, risk premium, CAPM and comparable earnings methods (PP&L St. 12, p. 3).

(1) Discounted Cash Flow (DCF)

The DCF theory is based upon finding the present value of an expected future stream of net cash flows during the investment holding period discounted at the cost of capital or capitalization rate. The capitalization rate is the total return rate anticipated and is commonly expressed in terms of the sum of a represented dividend yield plus the growth rate to capture investors' expectations of future increases in cash dividends (PP&L St. 12, pp. 38-39).

In developing his final recommendation, Mr. Moul updated his initial analysis by calculating dividend yields for PP&L and his Barometer Group based on the latest data available at the time he prepared his rebuttal testimony (PP&L St. 12-R, pp. 2-3). Since utility dividends generally increase from year to year and are paid on a periodic (quarterly) rather than continuous basis, Mr. Moul adjusted his dividend yield findings to capture one-half of the anticipated growth in dividends (PP&L St. 12, p. 41). This adjustment is necessary to recognize investors' expectations that the dividend will be raised at some point during the ensuing four calendar quarters and has been approved by the Commission in any number of prior rate proceedings.[54/] Mr. Moul's updated adjusted dividend yields were 8.46% for PP&L and 7.85% for his Barometer Group (PP&L St. 12-R, Sch. 1, p. 1).

Once the dividend yield is calculated, the proper growth rate must be developed. To this end, Mr. Moul reviewed historical dividend and earnings performance, published growth rate forecasts and retained earnings growth rate patterns. Based on his analysis of such statistical data, Mr. Moul selected a prospective growth rate of 4% for both PP&L and his Barometer Group (PP&L St. 12, p. 44). This reflects a 3.5% growth rate based on individual Company data and a .5% adjustment to reflect

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54/ Mr. Moul also adjusted the dividend yield to reflect the build up of the dividend in the price of the stock which occurs since the last "ex-dividend" date (the date which a shareholder must own the shares to be entitled to the dividend payment -- generally two to three weeks prior to the actual payment of the dividend) (PP&L St. 12, p. 40). OTS witnesses Deardorff and OCA witness Kahal asserted, without support, that such an adjustment was "unnecessary." Mr. Moul responded that the increased availability of data and the increased used of personal computers have made this refinement practical and available to investors and increases the accuracy of calculating dividend yields. Other commissions, particularly the New York Public Service Commission, have accepted this adjustment (PP&L St. 12-R, p. 16).

other market factors which affect growth. As explained by Mr. Moul:

> Therefore, for the purpose of this case I have added a modest 0.5% growth rate for market-wide factors to the growth rate shown by company-specific variables. As previously indicated, there are a wide variety of factors that influence investor expected returns which are not linked specifically to company-specific near-term performance. Those factors would include overall business conditions, monetary policy, fiscal and tax policy, all of which I would categorize as qualitative influences on investors' total return expectations. In addition, as the electric utility industry adjusts to the new business environment, additional opportunities will surely develop beyond the five-year horizon typically considered by the analysts' forecasts.

When combined with his adjusted dividend yield, Mr. Moul's proposed growth rate produced DCF findings of 12.46% for PP&L and 11.85% for his Barometer Group (PP&L St. 12-R, Sch. 1, p. 1). The difference in results reflects the greater risk of PP&L as compared to the Barometer Group.

(2) Risk Premium

The second method of determining equity return rates sponsored by Mr. Moul was the risk premium analysis. This method looks first at the cost of public utility bonds, and adds to that an appropriate risk factor to recognize the inherently greater risk associated with a common equity investment. See, e.g., Pa. P.U.C. v. Western Pennsylvania Water Co., 63 Pa. P.U.C. 157, 199 (1987).

In his analysis, Mr. Moul employed a prospective long-term debt attraction rate of 8.5% and a 4.75% equity rate premium (PP&L St. 12-R, Sch. 1, p. 1). The former figure was based upon his review of historic and projected yields for long-term public utility bonds. The latter figure, in turn, was derived from his own analysis of historical data, as well as analyses performed by others, and is designed to compensate investors for the additional risk of holding equity, as opposed to debt, securities (PP&L St. 12, p. 46 and App. B). Based on these findings, Mr. Moul concluded that the indicated cost of common equity for PP&L, utilizing the risk premium method, approximated 13.25% (PP&L St. 12-R, Sch. 1, p. 1).

The Company is, of course, aware that the risk premium method has met with mixed reviews in recent Commission proceedings. However, the Commission has indicated in its response to a recent NARUC survey that it considers all methods in determining the cost of equity capital. And, the Commission recently took "administrative notice" of risk premium findings to satisfy itself that its equity allowance was not understated. See Pa. P.U.C. v. West Penn Power Co., Docket No. R-00942986, 1994 Pa. PUC LEXIS 144, *148 (December 29, 1994). The Company submits that the risk premium method can provide important information on rates of return and should be considered by the Commission in this proceeding.

(3) Capital Asset Pricing Model

Mr. Moul also employed the Capital Asset Pressing Model (CAPM), applying both the traditional and zero-beta CAPM formulations to market data for PP&L and his Barometer Group (PP&L St. 12, p. 49). Under the CAPM method, which is derived from modern portfolio theory, the expected common equity return is determined by adding a risk-free rate of return and a market premium that is proportional to the non-diversifiable, or systematic, risk of a particular security. The non-diversifiable risk is obtained by the application of a "beta", which indicates the risk of an individual stock relative to the risk of the entire market. In other words, beta measures the volatility of a return for a particular security relative to the volatility of the market as a whole. The lower the beta, the less risky the stock, and the lower the cost of equity (PP&L St. 12, App. E).

As Mr. Moul explained, the proper risk-free rate of return to be utilized for long-lived utility assets is a long-term Treasury bond yield. He initially employed an 8.0% risk-free rate based on historical and forecast Treasury bond data (PP&L St. 12, pp. 50-51). In his rebuttal testimony, Mr. Moul updated this figure to 7.5% to reflect more recent data (PP&L St. 12-R, Sch. 2). To this updated figure Mr. Moul added market premiums of 5.29% for PP&L and 5.22% for his Barometer Group under the traditional method, and 2.66% for PP&L and 7.67% for the Barometer Group under the zero-beta method. Id. This produced

CAPM equity cost rate findings for PP&L of 12.79% under the traditional method and 13.92% under the zero-beta method, and 12.72% under the traditional method and 13.88% under the zero-beta method for his Barometer Group. Id.

(4) Comparable Earnings Approach

The fourth method used by Mr. Moul was the Comparable Earnings Approach. The Comparable Earnings Approach has been used extensively in rate of return analysis for over 50 years. Its popularity diminished in the 1970s and 1980s but recently there has been renewed interest in this approach. The financial community has expressed the view that the regulatory process must consider returns which are being achieved in the non-regulated sector so that utilities can compete effectively in capital markets (PP&L St. 12, pp. 35-36).

The consideration of returns available in non-regulated investments of similar risk is particularly important given the increased competition facing the electric utility industry. The risk difference between regulated and non-regulated companies is clearly decreasing. The comparable earnings method directly considers these issues. It also has considerable intuitive appeal because it directly addresses the established standards for a fair rate of return set forth in the U.S. Supreme Court decisions discussed above (PP&L St. 12, p. 36).

Mr. Moul initially employed a Value Line data base consisting of data and information for approximately 1600 companies. He then applied six risk criteria to establish a group of non-regulated companies with risks comparable to PP&L. Applying these six criteria, Mr. Moul developed a group of 23 non-regulated companies that were comparable in risk to PP&L. The results of this approach provided an historical comparable earnings return of 12.6% and a forecast return of 14.5%, with an average of 13.55% (PP&L St. 12, p. 37-38).

(5) Summary

In view of the foregoing, Mr. Moul recommended that the Company's equity allowance be set at 13% in this proceeding. The components of that analysis, to which Mr. Moul applied informed judgment, are set forth in the following table (PP&L St. 12-R, Sch. 2, p. 1):

Components of Mr. Moul's Proposed
Proposed Equity Cost Recommendation

	DCF	Risk Premium	Comparable Earnings	CAPM Traditional	Zero Beta
PP&L	12.46%	13.25%	13.55%	12.79%	13.92%
Barometer Group	11.85%	13.25%	13.55%	12.72%	13.88%

3. Opposing Parties' Equity Cost Recommendations

OTS witness Deardorff, OCA witness Kahal, PPLICA witness Baudino and DOD witness Prisco have recommended alternative cost of equity allowances in this proceeding. These allowances, ranging from 10.63% to 11.5%, each grossly understate the Company's current and prospective cost of equity and must therefore be rejected.

A primary flaw in the cost of equity presentations of each of the three principal rate of return witness in this proceeding, Messrs. Deardorff, Kahal and Baudino, lies in their sole and exclusive reliance upon the DCF approach to establish the cost of common equity.[55]

As Mr. Moul explained, no one cost of equity model is so inherently precise than it can be relied upon to the exclusion of all other methods (PP&L St. 12, p. 35). It is undoubtedly for this reason that 80% of the regulatory commissions recently surveyed by the National Association of Regulatory Utility Commissioners responded that they utilized more than one method to determine the cost of equity for ratemaking purposes (PP&L St. 12-R, Sch. 3). Opposing party witnesses ignore this overwhelming practice and rely exclusively on the DCF analysis.

Mr. Moul explained the central problem with the DCF model in his testimony PP&L St. 12-R, pp. 14-15):

55/ Unlike the other witnesses, Mr. Prisco conducted no detailed rate of return analysis, and simply asserted that PP&L should receive the same equity cost allowance -- 11.5% -- awarded to West Penn Power Company in its most recent rate case. As explained above, West Penn is far less risky than PP&L and does not represent a reasonable proxy for setting PP&L's equity cost rate.

> The constant growth or "Gordon" form of the DCF model has been used by all rate of return witnesses in this case. It must be recognized that this version of the DCF model is not without its limitations because many of the assumptions which must be made to utilize this model are simply not realistic. According to the theory of the constant growth form of the DCF, future earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same rate absent any change in price-earnings multiple. However, there is no evidence that these conditions actually prevail in the equity market.

Given these shortcomings, it is essential that this Commission rely upon other methods, at least as a check upon the reasonableness of DCF results.

As Mr. Moul also explained, a further critical flaw in the DCF method is that when applied to an original cost rate base it will understate a utility's cost of capital when the market prices of the stocks used in the analysis substantially exceed their underlying book value (PP&L St. 12, App. C). For this reason, several regulatory commissions have openly questioned the reliability of the DCF method given current market fundamentals.

For example, in a recent case the Indiana Utility Regulatory Commission discussed this problem as follows:

> In determining a common equity cost rate, we must again recognize the tendency of the traditional DCF model, relied on heavily by Mr. Bolinger, to understate the cost of common equity. As the Commission stated in Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18, "the unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible, and therefore requires

an upward adjustment based largely on the expert witness's judgment."

* * *

It is recognized that "there are difficulties in making a good DCF calculation whenever a utility's stock sells, for whatever reason, above book value." Niagara Mohawk Power Corp. (NY PSC 2/2/93), 140 PUR4th 481, 491. This phenomenon was also discussed in Whittaker, "The Discounted Cash Flow Methodology: Its Use In Estimating A Utility's Cost of Equity," 12 Energy L.J. 265, 281-282 (1991), where it is stated:

> The DCF methodology presumes to produce the "market required" return of equity, that is, the "cost of equity" on the market value -- not the book value -- of a company's stock. Unless the market price of a utility's stock equals its book value, the unmodified application of the market-oriented DCF results to a net original cost (book value) rate base understates the earnings necessary to satisfy the investor-required (expected) return.
>
> Thus, if the traditional DCF model is strictly applied to an original cost rate base, the investor could earn the cost of capital only if the investor paid no more than book value for the stock.

The Iowa Utilities Board reached the same conclusion in Re Interstate Power Co., 152 PUR4th 377, 382-83 (1994):

> The Board generally relies on the DCF model for the initial analysis to determine the cost of equity and uses a risk premium analysis as a check on the validity of the DCF analysis. In *Iowa Electric Light and Power Company*, Docket No. RPU-89-9, "Final Decision and Order" (October 25, 1990), the Board stated: "[T]he DCF model may understate the return on equity in some circumstances. This is particularly true when the market is volatile and the company in question has a market-to-book ratio in excess of one." Those conditions exist in this case (Ex. 17, Sch. 2, p. 3). The DCF results do not overlap with the

> risk premium analysis because the DCF model yields extremely low results.
>
> * * *
>
> In this case, the DCF approach underestimates the cost of equity needed to assure capital attraction during this time of market uncertainty and volatility . . . The Board will, therefore, give preference to the risk premium approach . . .

<u>See</u> <u>also</u> <u>Maui Electric Company Ltd.</u>, 153 PUR4th 437, 473 (1994) ("we agree with MECO that there is currently a downward bias in the DCF model"); <u>Re Commonwealth Edison Co.</u>, 158 PUR4th 458, 520 (1995) ("[T]he presentation made by Messrs. Gorman, Lelash and Kahal lead to determinations which understate Edison's cost of equity; e.g., used by all three intervener witnesses of an annual DCF model, which has been explicitly rejected by this commission.").

In light of the evidence, it should not be surprising that the explanations offered by the witnesses relying exclusively on the DCF model were less than convincing. Mr. Deardorff's assertions that the DCF model is "more direct" and more "forward looking" are simply wrong. Mr. Moul's other methods (risk premium, CAPM and comparable earnings) are as direct as the DCF, and each has a forward looking component to provide an expectational as well as an historic value (PP&L St. 12-R, pp. 20-23). And, the fall-back position of various witnesses that "everything is captured in the market price" is circular reasoning, assuming that the DCF model is accurate to begin with.

As a result of relying solely upon the DCF method, the witnesses in this proceeding have produced clearly unreasonable results. In his rebuttal testimony, Mr. Moul developed the following table setting forth the results which would flow from the opposing parties' recommendations (PP&L St. 12-R, p. 6):

Witness	Recommended ROE	PP&L Book Value	Earnings Per Share	Dividends Per Share	Amount Retained Per Share	Calculated Growth Rate	Recommended Growth Rate
Deardorff	10.63%	$15.79	$1.68	$1.67	$0.01	0.06%	2.75%
Baudino	10.85	15.79	1.71	1.67	0.04	0.25	2.05 - 3.05
Kahal	11.10	15.79	1.75	1.67	0.08	0.51	2.5 - 3.0

Several conclusions are apparent. The opposing party equity cost recommendations would produce earnings per share of $1.68 - $1.75, which is well below investor expectations of $1.97 - $2.05/share as estimated by analysts' forecasts. Moreover, these earnings levels are only marginally above PP&L's current dividend of $1.67/share and would permit little if any growth. Specifically, the opposing party recommendations would permit growth of .06%-.51% as compared to the witnesses' proposed DCF growth rates of 2.5-3.05%.

By refusing to consider the use of other equity cost rate models, the opposing party witnesses severely compromised the scope and reliability of their analyses. This threshold shortcoming was then compounded through the misapplication of the one method on which they chose to rely.

For example, Mr. Deardorff's mechanical application of the DCF model produced obviously unreasonable results for both PP&L, and his barometer group companies. Mr. Deardorff's analysis of his Value Line barometer group determined that the cost of equity for his individual companies produced DCF calculations as low as 9.25% for a barometer group and 9.4% for PP&L while some of the barometer group companies had individual DCF calculations as low as 8.2% to 8.5% (PP&L St. 12-R, p. 19-20). These results are clearly unreasonable, yet if one accepts the standard regulatory version of DCF, these results must show the expected cost of common equity. The simple answer is that the DCF method cannot be used in isolation and without careful exercise of informed judgment.

Similarly, Mr. Kahal's proposed DCF growth rate specifically assumed returns on equity in a 12% to 12.5% range (PP&L St. 12-R, pp. 17-18). Mr. Kahal did not and, of course, could not explain how PP&L can achieve these anticipated growth rates under his proposed 11.1% return on equity.

Mr. Baudino carries DCF "gaming" to its extreme by openly mismatching growth rates in a transparent effort to simply produce the lowest possible growth (PP&L St. 12-R, p. 19).

Finally, the opposing parties engage in lengthy attacks on Mr. Moul's methods and calculations. These criticisms are fully addressed in Mr. Moul's rebuttal (PP&L St. 12-R) and rejoinder (Tr. 1833-1841) testimony and will not be restated here. These various attacks should not be allowed to obscure the fundamental flaws in the opposing party recommendations: Their sole reliance on DCF and failure to produce reasonable results when compared to the return allowances by this Commission in recent proceedings for utilities with clearly less risk than PP&L.

VIII. RATE STRUCTURE

A. Cost Of Service

In accordance with Commission regulations, at 52 Pa. Code §53.53, et seq., the Company presented a fully-allocated cost of service study showing the distribution of its jurisdictional costs to the various classes of customers at both present and proposed rates for the historic (Ex. JMK-1) and future (Ex. JMK-2) test years. The Company's witness, Mr. Joseph M. Kleha, applied well-established and reasonable cost allocation principles in his studies (See Ex. JMK-1 at pp. 3-6). Much of his cost allocation study results were not challenged by any party and will not be discussed here.

The opposing parties did propose several revisions. Predictably, each party urged adjustments that would most favor the interests of its own rate class. In contrast, as the party without the same incentive to favor one rate class or another, the Company has taken a reasonable, middle-of-the-road position in each instance.[56]

As this Commission has repeatedly recognized, cost of service is only a guide to designing rates and is only one factor, albeit an important one, to be considered in the rate

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[56] PP&L St. 7-R, p. 3. Significantly, the only other party not associated with a particular customer class, the OTS, did not challenge the Company's cost of service study.

setting process.[57/] Moreover, cost of service analysis is not an exact science, and there is no single "correct" method of cost allocation. The Company's cost of service study steers clear of extreme impacts, produces reasonable results and should be approved.

1. Generating And Transmission Plant Costs

a. PP&L's 12 Coincident Peak Allocation Methodology Should Be Approved

The Company used the monthly peak demand responsibility allocation methodology ("12 CP") to allocate generating and transmission plant costs. This approach is based on the average of the twelve monthly coincident class demands at the time of the system monthly peak loads. See Ex. JMK-1, p. 116. The 12 CP method recognizes that generating costs are incurred to meet peak demand requirements, but also recognizes that these demand requirements continue throughout the year. The 12 CP method was approved in the Company's last base rate case and has been employed in all cost of service study previously submitted by the Company to this Commission and FERC (PP&L St. 7-R, p. 4).

57/ In Peoples Natural Gas Company v. Pa. P.U.C., 47 Pa. Cmwlth. 512, 409 A.2d 446, 458 (1979), the court noted that, "multiple factors necessarily affect the appropriateness of a rate structure," and criticized the intervenor/petitioners as having, "emphasized the cost-of-service study to the exclusion of other, equally appropriate factors." Those factors include: "quantity of electricity used, nature of the use, time of the use, pattern of the use, differences in conditions of service and cost of service, in addition to economic facts and circumstances which affect rates and services." Id.

Use of the 12 CP method is appropriate for at least four reasons: (1) rate stability; (2) recognition of the Company's PJM obligations, which require it to provide a levelized amount of capacity over a 12-month period; (3) recognition of class diversities; and, (4) adequate recognition of the role of scheduled generating plant maintenance (PP&L St. 7, pp. 6-7; PP&L St. 7-R, pp. 4-6.)

Two different, and diametrically opposed, proposals were advanced by intervenors. At one extreme, the University/College Coalition ("UCC") proposed a single winter peak methodology.[58/] At the other extreme, the OCA proposed a "peak-and-average" method, under which both winter and summer peaks and energy usage throughout the year would determine demand cost allocation (OCA St. 3, pp. 9-13). The merits of these recommendations are discussed below. Significantly, however, each proposal would skew costs dramatically toward one major customer class. The OCA proposal would allocate about 60% of the costs associated with PP&L's generating and transmission plant on an energy basis. This would benefit residential customers and substantially increase the responsibility of large industrial users (PP&L St. 7-R, p. 9). In contrast, the 1 CP method would

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58/ UCC St. 1, pp. 5-6. Mr. Baron, on behalf of PPLICA, criticized the 12 CP method on similar grounds, stated a preference for the 1 CP method, but he did not recommend a change in this rate case (PPLICA St. 1, pp. 17-19). Similarly, Mr. Brubaker on behalf of Bethlehem Steel briefly criticized the 12 CP method, but did not recommend an alternative (BSC St. 1, p. 8).