ORIGINAL

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF
PENNSYLVANIA POWER & LIGHT COMPANY
FOR APPROVAL OF RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

Docket No. R-00973954

PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

ON BEHALF OF PP&L, INC.

TO ADMINISTRATIVE LAW JUDGE GEORGE M. KASHI

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PROPOSED FINDINGS OF FACT

PROCEDURAL HISTORY

1. On December 3, 1996, Governor Ridge signed into law the Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §§ 2801 et. seq. (the "Act"). The Act fundamentally restructures the provision of retail electric service in Pennsylvania by mandating the phase-in of customer choice of electric generation supplier ("EGS") beginning January 1, 1999.

2. Section 2806 of the Act requires Pennsylvania jurisdictional utilities to file Restructuring Plans for Commission approval. By Order entered January 24, 1997 at Docket No. M-00960890.F05, the Commission directed PP&L to file its Restructuring Plan on April 1, 1997. In accordance with the Commission's January 24, 1997 Order, PP&L filed its Restructuring Plan on April 1, 1997.

3. PP&L in its Restructuring Plan filing, as revised during this proceeding: (a) proposed the unbundling of its rates and establishment of competitive transition charges ("CTCs") and specific tariff provisions to ensure customers direct access to all licensed EGSs; (b) projected its transition costs under the Act at $4.5 billion; (c) proposed a plan to meet its universal service obligations, including a mechanism to recover the costs of those obligations; (d) described the implementation of a consumer education program; and (e) proposed procedures for implementing PP&L's responsibilities as provider of last resort under 66 Pa.C.S. § 2807(e)(3) ("Last Resort Service").

4. Copies of the filing were served on all active participants in PP&L's last general base rate investigation at Docket No. R-00943271. PP&L provided notice of its Restructuring Plan filing to all customers by bill insert beginning with the April 1997 billing cycle and all persons who requested a copy. The Company further provided a one-page notice of its filing to all individuals on the Executive Director's Stakeholder list. In addition, notice of the filing was published in newspapers of general circulation in PP&L's service territory.

5. PP&L's Restructuring Plan filing was assigned to Administrative Law Judge George Kashi, and a first prehearing conference was convened in Harrisburg on April 18, 1997. Second and third prehearing conferences were held in Harrisburg on May 16, 1997 and July 15, 1997, respectively.

6. Thirty-nine parties were permitted to intervene in this proceeding. Of that group, seventeen intervenors have maintained active party status.[1/] In addition, Formal

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1/ The active parties are as follows: Office of Consumer Advocate; Office of Small Business Advocate; Office of Trial Staff; Allegheny Power; American Association of
(continued...)

Complaints against the Company's Restructuring Plan were filed by the OCA, PPLICA and the Environmentalists.

7. PP&L submitted with its Restructuring Plan filing extensive supporting information, including the direct testimony and supporting exhibits of seventeen witnesses and responses to the Commission's filing requirements. Supplementing that information, PP&L has responded to nearly 1000 interrogatories and data requests and has exchanged a significant amount of information with parties on an informal basis. In addition, an informal technical conference was held in Harrisburg on May 2, 1997, at which PP&L made available several of its witnesses to answer questions and further explain their testimony.

8. On July 2, 1997, the intervenors submitted extensive direct testimony addressing almost every aspect of PP&L's Restructuring Plan. On August 5, 1997, PP&L responded to the intervenors' direct testimony by filing rebuttal testimony and exhibits sponsored by twenty witnesses. A number of the intervenors submitted surrebuttal statements on August 15, 1997.

9. Evidentiary hearings were held in Harrisburg on August 18-22 and August 25-29, 1997 and on September 9, 1997. During those hearings 284 exhibits and the testimony of 57 witnesses were admitted into evidence. The transcribed record of the evidentiary hearing consists of 2,337 pages. The evidentiary record was closed on September 9, 1997.

10. Thirteen public input hearings were held during the weeks of May 30, 1997 and September 2, 1997. Public input hearings were held in Allentown (June 2), Bethlehem (June 2 and September 3), Harrisburg (May 30 and September 3), Hazleton (June 4),

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Retired Persons; Commission on Economic Opportunity; Enron Power Marketing Inc.; Environmentalists; Local 1600, International Brotherhood of Electric Workers; Eric Epstein; Gilberton Power; Mid-Atlantic Power Supply Association; New Energy Ventures; Pennsylvania Petroleum Association; PP&L Industrial Customer Alliance; Schuylkill Energy Resources; United States Department of Defense. The inactive parties are as follows: Allegheny Electric Cooperative; American Energy Solutions; Anthracite Regional Power Producers; Bethlehem Steel; Center for Energy and Economic Development; Delmarva Power & Light; Duke Energy Trading Marketing; Dupont Power Marketing; Electric Clearinghouse Inc.; ERI Services Inc.; GPU Energy; Kraft Foods; Noram Energy Management; PECO Energy Company; Pennsylvania Association of Plumbing Heating & Cooling Contractors; Pennsylvania Electric Consumers Council; PP&L Rate Payers Association; Pennsylvania Retailers Association; Vastar Power Marketing.

Lancaster (May 30 and September 2), Pottsville (June 4), Scranton (June 3 and September 4), Williamsport (June 5), and Wilkes-Barre (June 3).

11. Following the hearings, at the urging of the presiding administrative law judge, the parties entered into settlement discussions. To accommodate those discussions and other events relating to the restructuring of the industry, the post-hearing briefing and decision schedule was extended several times. Orders extending the briefing schedule and the date for Commission decision in the case were issued on September 12, 1997, October 17, 1997, November 25, 1997 and December 24, 1997.

I. CONTEXT OF RESTRUCTURING

12. Electric companies have been viewed as natural monopolies in Pennsylvania since the adoption of the Public Service Company Law of July 26, 1913, P.L. 1374 (repealed), as amended by section 4 of the Act of June 3, 1933, P.L. 1526, 66 P.S. §201-2 (repealed).

13. The Public Service Law and its successors recognize that in exchange for a monopoly to provide service in an exclusive service territory, public utilities were both exempted from competition and obligated to provide service within that service territory. Regulation of rates and service was determined to be necessary to replace the lack of competition.

14. An overriding theme of traditional monopoly regulation of electric utilities has been described as the regulatory bargain or regulatory compact. The regulatory compact was described by PP&L witness Kalt, as follows:

> In the pre-reform regulatory setting, utilities and the investors who provide utility capital accepted an obligation to serve all electric demand in their service territory. Pursuant to this obligation to serve, utilities accepted the obligation to incur the costs of sufficient generation and related capacity to ensure that expected demand could be satisfied, with these investment plans being subject to review and oversight by regulators and with their decisions reflected in just and reasonable rates regulators have allowed utilities to charge their customers. Investors in utility companies agreed to provide the capital necessary to make these investments under regulatory rules that subjected cost recovery to cost-of-service regulatory principles rather than market forces.
> PP&L St. 1, pp. 11-12.

15. Pursuant to this system of regulation, PP&L invested billions of dollars to construct generating stations to meet the reasonably projected needs of customers in its service territory. These investments previously have been reviewed by the Commission and adjudged to be prudent expenditures. Accordingly, under a continuation of regulated

monopoly service, PP&L and its investors would have had an opportunity to recover both a return of, and a reasonable return on, such investments to provide service to customers.

16. Economic circumstances have changed, however, leading the General Assembly to conclude that the generation of electricity, as distinguished from its transmission and distribution, is no longer a natural monopoly. PP&L witness Dr. Alfred Kahn explained:

> What has changed since then? Manifestly, the relationship between price and marginal cost, both short- and long-run: what other answer would you expect from an academic economist?
>
> The reasons for that dramatic change are familiar: First, the entry into service of long-lead-time base-load plants, constructed over a period of double-digit inflation of interest rates and construction costs and in anticipation of a continued expansion of demand at 6 to 7 percent annual rates. These developments and the abrupt deceleration of demand left utilities, particularly on the East and West coasts, with average generating costs in the range of perhaps 6 to 10 cents a kwh and, because of their excess capacity, short-run marginal costs of 1 to 2 cents. Second the collapse of fossil fuel prices in the middle 1980s, in combination with, third, the development of combined cycle gas turbine technology, which have made it possible to build 100-megawatt or smaller new plants with average costs on the order of 4 cents a kwh.
>
> Fourth, the nuclear fiasco. And, fifth, PURPA, with its legacy of multi-billion dollar contractual obligations of the electric companies to buy independently generated power at rates set at avoided costs estimated by regulators on the basis (among other consideration) of expectations that the price of oil would by now be nearing $100 a barrel.
>
> All these developments have combined to produce regulated rates in some regions of the country, far above both short- and long-run marginal costs. And that in turn has created irresistible temptations for sellers - including utility companies, *outside* their own franchise territories - to offer eager buyers an escape from those inflated rates. PP&L St. 18-R, pp. 21-22)

17. In 1992 Congress passed the Energy Policy Act which specifically empowered the Federal Energy Regulatory Commission ("FERC") to order public and privately owned utilities to grant access to their transmission systems for qualified entities engaging in wholesale power transactions. 16 U.S.C. §824(j),(k).

18. The FERC dramatically expanded the availability of transmission by issuing, in 1996, Order No. 888 requiring the public utilities to unbundle wholesale contracts and offer open access non-discriminatory transmission to all eligible customers — including retail customers in states implementing retail competition — while providing for the recovery of stranded costs incurred as a result of opening up the transmission system.

19. The significant metamorphosis in the economics of producing electric power has led the General Assembly to conclude that generation of electricity can be provided more efficiently (at lower costs) under a competitive system. As the General Assembly concluded:

> Because of advances in electric generation technology and federal initiatives to encourage greater competition in the wholesale electric market, it is now in the public interest to permit retail customers to obtain direct access to a competitive generation market as long as safe and affordable transmission and distribution service is available at levels of reliability that are currently enjoyed by the citizens and businesses of this Commonwealth. 66 Pa.C.S §2802(3).

20. The Act substitutes a competitive system for determination of the generation prices for the previously employed regulated system.

21. The Act contains declarations of policy which set forth the reasons that the General Assembly has directed the restructuring of the electric industry in Pennsylvania. 66 Pa.C.S.§2802. The Act also contains specific standards for restructuring of the electric industry. 66 Pa.C.S. §2804. These declarations and standards set the bounds within which the restructuring of the electric industry is to be conducted and within which the issues in this proceeding must be resolved.

22. In adopting the Act, the General Assembly recognized the need for a fair transition from regulation to competition:

> In moving toward greater competition in the electricity generation market, the Commonwealth must resolve certain transitional issues in a manner that is fair to customers, electric utilities, investors, the employees of electric utilities, local communities, non utility generators of electricity and other affect parties. 66 Pa.C.S. §2802(9).

23. In section 2802(12), the General Assembly declares that:

> The purpose of this chapter is to modify existing legislation and regulations and to establish standards and procedures in order to create direct access by retail customers to the competitive market for the generation of electricity while maintaining the safety and reliability of the electric system for all parties. Reliable electric service is of the utmost importance to the health, safety and welfare of the citizens of the Commonwealth. Electric industry restructuring should ensure the reliability of the interconnected electric system by maintaining the efficiency of the transmission and distribution system. 66 Pa.C.S. §2802(12).

24. In order to protect customers while transitioning to a competitive market for generation of electricity, Section 2804(4) of the Act provides for rate caps. These rate caps are designed to protect customers from increases in rates over the levels in effect at the time of adoption of the Act, that might result from the transition to a competitive market.

25. The Act also recognizes the fact that electric utilities and their investors have invested billions of dollars in generating facilities, that some of these costs may not be recovered under a competitive system and that electric utilities should be permitted to recover such costs during the transition period to the extent possible within the rate cap:

> In establishing the standards for the transition to and creation of a competitive electric market, heretofore, public utilities generally have had an obligation to serve customers within their defined service territories; consistent with that obligation, have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers; and have entered into long-term power supply agreements as required by Federal law. In many instances, these investments and agreements have created costs which may not be recoverable in a competitive market. The commission is empowered under this chapter to determine the level of transition or stranded costs for each electric utility and to provide a mechanism, the competitive transition charge, for recovery of an appropriate amount of such costs in accordance with the standards established in this chapter. 66 Pa.C.S. §2802(15).

26. The Act establishes the manner in which competition will be conducted. In this regard the Act provides that:

> This chapter requires electric utilities to unbundle their rates and services and to provide open access over their transmission and distribution systems to allow competitive suppliers to generate and sell electricity directly to consumers in this Commonwealth. The generation of electricity will no longer be regulated as a public utility function except as otherwise provided for in this chapter. Electric generation suppliers will be required to obtain licenses, demonstrate financial responsibility and comply with such other requirements concerning service as the commission deems necessary for the protection of the public. 66 Pa.C.S. §2802(14) (Emphasis added).

27. To implement open access, the Act sets forth certain standards to which the Commission must adhere:

> The commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure. 66 Pa.C.S. §2804(5).
>
> Consistent with the provision of section 2806, the commission shall require that a public utility that owns or operates jurisdictional transmission and distribution facilities shall provide transmission and distribution service to all retail electric customers in their service territory and to electric cooperative corporations and electric generation suppliers, affiliated or nonaffiliated, on rates, terms of access and conditions that are comparable to the utility's own use of its system. 66 Pa.C.S. §2804(6).
>
> The commission shall require that restructuring of the electric utility industry be implemented in a manner that does not unreasonably discriminate against one customer class to the benefit of another. 66 Pa.C.S. §§2804(7).

28. In addition to providing for a retail access pilot (66 Pa.C.S. § 2806(G)), the General Assembly also obligated each electric distribution company to implement, in conjunction with the Commission, a consumer education program that "shall provide consumers with the information necessary to help them make appropriate choices as to their electric service." 66 Pa.C.S. § 2807(d)(3).

29. The Act further seeks to protect customers who, for any number of reasons, do not or cannot obtain service from a competitive electric supplier. In this regard, the Act contains specific policy determinations concerning continuation of programs that

currently assist low-income customers (66 Pa.C.S. §2802(10) and other public purpose programs. 66 Pa.C.S. §2802(17).

30. The Act also contains requirements applicable to electric companies that are intended to provide all customers with reliable transmission and distribution service and to provide all customers with a supplier of last resort. 66 Pa.C.S. §2802(16).

II. LEGAL AND POLICY FOUNDATIONS OF STRANDED COST RECOVERY

31. The Act addresses stranded costs in three different ways. First, the "Declaration of Policy," Section 2802(15), establishes the general need for and appropriateness of recovery by electric distribution companies of their stranded costs as follows:

> In establishing the standards for the transition to and creation of a competitive electric market, heretofore, public utilities generally have had an obligation to serve customers within their defined service territories; consistent with that obligation, have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers; and have entered into long-term power supply agreements as required by Federal law. In many instances, these investments and agreements have created costs which may not be recoverable in a competitive market. The commission is empowered under this chapter to determine the level of transition or stranded costs for each electric utility and to provide a mechanism, the competitive transition charge, for recovery of an appropriate amount of such costs in accordance with the standards established in this chapter.

Second, the Act provides a general definition of "stranded costs." Section 2803 defines "stranded costs" to be:

> An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the commission determines will remain following mitigation by the electric utility.

Third, Section 2804(14) of the Act mandates an "orderly" transition to competition designed to:

> protect electric system reliability, be fair to ratepayers and provide the investors in Pennsylvania electric utilities with a fair opportunity to fully recover the amount of transition or stranded costs that the Commission determines to be just and reasonable.

32. Sections 2802(15), 2803 and 2804(14) of the Act mandate that the Commission allow recovery of a level of stranded costs determined to be just and reasonable. In adopting these provisions, the General Assembly has balanced the interests of electric utilities and ratepayers in an appropriate manner. The Act seeks to attain, on one hand, the benefits for customers of low-cost electric generation that is becoming available, as explained above, from technological advances and reduced fuel prices. On the other hand, the Act permits electric utilities to recover their prudently-incurred costs, that would be recoverable under the prior system of regulation, but which may not be recoverable under a competitive regime.

33. Regulated utilities in Pennsylvania operated under a requirement of mutual obligations, regardless of whether those obligations are referred to as a "regulatory compact," "regulatory bargain," "understanding," or something else. The essence of that initial obligation was that utilities had a fair opportunity to recover their prudently-incurred investments in facilities used to meet their obligation to serve all customers. PP&L witness Professor Kalt described the obligation as follows (PP&L St. 1, pp. 11-12):

> Despite semantic and legalistic arguments to the contrary, it has been recognized at the highest levels of economic and public policy-making that there exists a 'regulatory compact' that has historically governed the relationship between regulated utilities and the government; and that this compact appropriately requires that regulatory reform not take away the reasonable prospect for recovery of costs that utilities incurred pursuant to their obligations under the regulatory regime in place at the time of their key cost-creating decisions. In the pre-reform regulatory setting, utilities and the investors who provide utility capital accepted an obligation to serve all electric demand in their service territory. Pursuant to this obligation to serve, utilities accepted the obligation to incur the costs of sufficient generation and related capacity to ensure that expected demand could be satisfied, with these investment plans being subject to review and oversight by regulators and with their decisions reflected in the just and reasonable rates regulators have allowed utilities to charge their customers. Investors in utility companies agreed to provide the capital necessary to make these investments under regulatory rules that subjected cost recovery to cost-of-service regulatory principles rather than market forces.

34. PP&L witness Professor Alfred Kahn reinforced Professor Kalt's conclusions, stating (PP&L St. 18-R, p. 10):

> I emphatically assert that there has indeed been a general understanding, over many decades, under original cost or prudent investment regulation such as has been practiced in the great majority of our jurisdictions, that the utility companies, in exchange for thoroughgoing regulation and the undertaking of costly public service responsibilities, were entitled to a reasonable opportunity to recover their prudently incurred costs . . . .

35. The General Assembly expressly recognizes the general principles of this bargain or understanding in the Declaration of Policy at Section 2802(15) of the Act. There, the General Assembly acknowledges the historic obligation of utilities to make substantial investments in facilities or contracts to provide safe and reliable service. The General Assembly recognizes also its obligation to allow recovery of costs stranded by the change the electric generation portion of electric utilities' business from a regulated monopoly to an unregulated competitive service.

36. Claims that this bargain or understanding does not exist deny the facts. Clearly, utility investors relied on prior rules concerning the prudent investment standard and fair rates of return in forming their expectation concerning risks and returns. PP&L St. 1-R, pp. 5-7.

37. The transition to a competitive market for electric generation is a fundamental change in the basic rules by which electric generation services have been provided. Electric utilities must be allowed a fair opportunity to recover investments in facilities made uneconomic by the change in regulatory policy. Any contrary breach of the Commonwealth's obligation to utility investors would be poor public policy, would be contrary to sound economic principles and would be inconsistent with prior law.

38. Under Section 2808(c)(4), in determining the level of stranded costs to be recovered, the Commission is to consider the extent to which the electric utility has mitigated generation-related stranded costs. The Act identifies examples of mitigation steps, and further directs the Commission to consider both mitigation in conjunction with restructuring and pre-restructuring efforts.

39. PP&L's mitigation efforts have been substantial and successful in reducing its stranded costs. The ultimate proof of the effectiveness of PP&L's pre-restructuring mitigation, however, is PP&L's success in controlling its rates, which the Act declares to be of "equal importance" with future efforts to mitigate stranded costs. See 66 Pa.C.S. §2808(c)(5).

40. PP&L's total rates are lower than those of other electric utilities. As shown at pages 16-19 of PP&L St. 9 and in Exhibit SFT 2, PECO's average rate is 9.91¢ per kWh; Duquesne Light Company's average rate is 8.92¢ per kWh. The Pennsylvania statewide average rate is 7.93¢ per kWh. PP&L's average rate of 7.21¢ per kWh is significantly lower than these other rates. In fact, PP&L's rates are now almost as low as the national average of 6.89¢ per kWh, while the spread between Pennsylvania's average rate and the national average rate has stayed relatively constant. PP&L Exhibit SFT 4.

41. PP&L's efforts to control costs and rates have been especially beneficial to residential customers. PP&L's rates for residential service have dropped below the national average, while Pennsylvania's average residential rate has been well above the national average. PP&L Exhibit SFT 5.

42. PP&L's low rates have resulted from cost control efforts by PP&L.

43. In recent years, PP&L has taken advantage of reductions in the cost of capital to refinance higher cost securities. During the 10½ years between its last two rate cases, PP&L reduced its long term debt cost rate by almost 30 percent.

44. PP&L was also able to reduce substantially its cost rate of preferred stock. These capital cost reductions reduced PP&L's revenue requirement in its 1994 base-rate case by $100 million. PP&L St. 2, pp. 6-7.

45. After PP&L's 1985 rate case, PP&L undertook cost containment efforts which included elimination of functions that had become unnecessary, restructuring of the corporate offices and reengineering of critical processes to combine functions where feasible. As a result of these efforts, PP&L's operation and maintenance production costs have increased by only 16 percent over 10 years and, adjusted for inflation, have actually declined by 15 percent.

46. PP&L also has reduced costs through increasingly efficient utilization of employees. PP&L St. 2, p. 8. From 1985 through 1996, PP&L has reduced its employee complement by 2,005 regular full-time employees, almost 24 percent of its 1985 work force. PP&L, however, has implemented work force reductions in a manner to minimize adverse effects upon former employees. Most reductions occur through normal attrition, early retirement programs and voluntary severance programs.

47. In 1991, PP&L modified its accounting for spare parts at power plants. As a result, PP&L was able to pass back $94 million to customers over 5 years through a rate credit mechanism. PP&L St. 2, pp. 8-9.

48. PP&L also reviewed its spare parts inventories to identify obsolete or excessive items. As a result of the review, PP&L wrote off $35 million of inventory, further mitigating PP&L's stranded costs. PP&L St. 2, p. 9.

49. Approximately 62 percent of PP&L's stranded costs relate to the Susquehanna Steam Electric Station, which includes two nuclear generating units. PP&L has undertaken significant measures that have reduced stranded costs associated with this facility. *See generally* PP&L St. 2, pp. 9-11.

50. PP&L completed Susquehanna as quickly as possible in order to minimize associated capital costs. As a result of these and other measures, PP&L was able to complete construction of two large nuclear units at a total cost of approximately $3.6 billion for 1,890 megawatts of capacity or approximately $1,900 per kilowatt. Other plants in Pennsylvania and in the United States, which were constructed contemporaneously with the Susquehanna Units, were completed at significantly higher costs per kilowatt. PP&L St. 2, p. 10.

51. Following completion of Susquehanna, PP&L pursued claims against the containment supplier, General Electric. PP&L settled its claim against General Electric in 1991, and obtained Commission approval to refund the jurisdictional amount of the net settlement proceeds --$55 million-- to customers through a special rate credit mechanism. PP&L St. 2, p. 10.

52. PP&L has also operated Susquehanna at as high a capacity factor as possible. Thus, PP&L has minimized periods when Susquehanna was not operating. Because nuclear power plants have high capital costs, but low fuel costs, their efficiency depends upon the capacity factor — the more a nuclear generating plant operates, the more it generates fuel savings. Susquehanna's excellent operating record has reduced PP&L's energy costs and customers' rates. Further, because such historical operating record has been projected to continue in the future, it reduces PP&L's stranded costs in this proceeding. PP&L St. 2, pp. 10-11. More recently, between 1991 and 1995, PP&L spent $45 million to upgrade Susquehanna's capacity by 90 megawatts, or $500 per kilowatt. This upgrade of Susquehanna's capacity produces additional energy cost savings for customers.

53. PP&L has operated its fossil fuel generating plants efficiently and has made substantial expenditures to assure the continued viability of low cost, coal-fired generating stations. These generating stations benefit customers through low fuel costs and increased interchange sales, which both lower retail rates. PP&L St. 2, p. 11.

54. PP&L has also invested to improve the efficiency of other fossil fuel plants. For example, PP&L converted its Martins Creek Units 3 and 4 to gas/oil dual fuel capability. PP&L now can burn gas or oil, whichever costs less, at these Units 3 and 4, which makes them more cost effective. PP&L St. 2, p. 11.

55. Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), PP&L was compelled to enter into long-term supply contracts with Non-utility Generators ("NUGs"). Rates in these agreements were based upon future market prices of fuels, which were projected when contracts were executed. Then, the price of oil was expected by now to be nearing $100 a barrel. PP&L St. 18-R, p. 22. NUG contract prices have turned out to be greater than PP&L's avoided costs of replacement generation or purchased power.

56. In order to reduce the level of stranded costs resulting from uneconomic NUG contracts, PP&L has undertaken several actions which have reduced stranded costs by $100 million.

57. PP&L has promoted economic development in order to retain existing, and to attract new, industrial load. PP&L has been "prospecting" nationally to attract businesses to its service territory. PP&L has worked with regional economical development organizations and has provided economic development loans in order to attract industrial load and jobs to its service territory. PP&L has adopted specific tariff provisions and rates, subject to the Commission's approval, to promote economic development, including the interruptible service rates, Economic Development Initiative ("EDI") credits, Industrial Development Initiative ("IDI") credits and Demand Free Days. PP&L St. 2, p. 13.

58. PP&L's economic development initiatives have helped PP&L avoid rate increases and have generated thousands of new jobs in PP&L's service territory. PP&L St. 2, pp. 13-14.

59. PP&L has calculated its stranded costs to be $4.5 billion. PP&L St. 2, p. 18. PP&L has proposed in this proceeding, however, a competitive transition charge ("CTC") that will produce only $4.001 billion, resulting in a shortfall of $500 million. PP&L St. 10-R, p. 3. Under PP&L's proposal, PP&L's shareholders will bear an estimated $500 million of stranded costs.

60. This CTC revenue shortfall of $500 million is based upon projected future electric generation market prices. However, PP&L's filing assumes that most of its fixed costs will be recovered as a result of future electricity market price and sales increases. If PP&L's projections overstate actual future market prices, PP&L's total revenues will decrease and its unrecovered stranded costs will increase commensurately.

61. Pursuant to Section 2808(c)(4)(iii), one of the mitigation steps that electric utilities are to consider is reallocating depreciation reserves from transmission and distribution plant accounts to generation accounts. In its filing, PP&L has proposed to transfer $205 million of its depreciation reserve related to transmission and distribution plant to the accumulated reserve for depreciation associated with its Susquehanna Units. The transfer of the depreciation reserve, together with the changes in the reserve for deferred income taxes, would reduce PP&L's stranded costs by $317 million. PP&L St. 2, p. 17.

62. OCA, the Department of Defense and the Environmentalists have opposed the proposed transfer of the depreciation reserves. They have raised four grounds for rejecting PP&L's proposal:

(1) the transfer will shift costs between rate classes at the jurisdictional level and between retail and wholesale customers;

(2) the transfer will lead to load growth, with adverse environmental impacts;

(3) the transfer will reduce shareholder exposure while increasing regulated transmission and distribution costs; and

(4) Transfer would result in transmission and distribution customers paying costs twice.

63. The parties' concerns lack merit. There is no cost shifting between rate classes at the retail jurisdictional level because PP&L's unbundled rates were derived from its cost of service study approved in its 1995 base-rate case, which was not modified to reflect the swap of the depreciation reserve. PP&L St. 3-R, pp. 12-13.

64. PP&L's proposal will not result in cost shifting between federal and state jurisdictions. Any such possible cost shifting will be avoided by PP&L's creation of a regulatory asset applicable to the transmission and distribution functions which equals the allocated depreciation reserve to be transferred. Under this proposal, the net decreased to the depreciation reserve for the Pennsylvania jurisdictional portion of the transmission and distribution function will equal the Pennsylvania jurisdictional portion of the increase to the depreciation reserve for the nuclear generation function.

65. The parties' second criticism of PP&L's proposed depreciation swap is in error and is contrary to the express purpose of the Act. The small change in rates that could result from the depreciation swap will not affect customers' usage patterns. PP&L St. 8-R, p. 53. Further, one purpose of the Act is to achieve lower rates to improve the economy of Pennsylvania. *See generally* 66 Pa.C.S. § 2802. The Act encourages mitigation of stranded costs for the purpose of reducing electric utilities' CTCs, thereby lowering rates.

66. The parties' third argument is in error. Customers are protected from overrecovery by electric distribution companies of transmission and distribution costs through the applicable rate cap. Consequently, customers cannot be harmed by a reduction in PP&L's stranded costs. Further, the "depreciation swap" is one of the mitigation procedures expressly contemplated in Section 2808(c)(4)(iii) of the Act.

67. In computing stranded costs, PP&L has projected approximately $513 million of unspecified reductions to future operation and maintenance and administrative and

general costs. These projections reflect a continued commitment to cost cutting and an estimate of the reductions that PP&L expects to achieve. If PP&L for any reason is unable to achieve the projected $513 million of future cost reductions, PP&L and its investors will bear the costs that PP&L is unable to avoid.

68. In PP&L's most recent base rate case, the Commission approved PP&L's proposal to modify the method by which it accrues depreciation on its Susquehanna Units. PP&L had used a modified sinking fund method in order to moderate rate increases associated with placing these units into rate base. PP&L proposed, commencing January 1, 1999, to switch to a straight line method of depreciation, under which it would experience a reduction in its annual depreciation accrual of an estimated $71 million. In conjunction with its proposal to change the depreciation method, PP&L proposed also to reduce base rates effective January 1, 1999, to reflect the effects of this switch in depreciation method. The Commission approved PP&L's proposal. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, pp. 106-113 (September 27, 1995).

69. As a result of the fundamental changes in regulatory policy under the Act which imposes rate caps on PP&L from January 1, 1997 through 2005, such a rate reduction is no longer appropriate. PP&L St. 10, pp. 9-10. Under the prior rate regime, PP&L could have filed base-rate cases in 1997, 1998 or anytime thereafter in order to recover increased costs of providing electric service. Therefore, it was reasonable under traditional rate regulation to flow through to ratepayers the effects of the change in depreciation method. Under the Act, however, PP&L has been denied the opportunity to increase base rates commencing January 1, 1997 and for nine years thereafter. Under these circumstances, it is more appropriate to permit PP&L to use the reduction in the annual depreciation accrual for the Susquehanna Units to accelerate amortization of regulatory assets and post-transition NUG costs. PP&L St. 2, pp. 18-19. Under the policy of the Act to mitigate stranded costs, the reduction in the annual depreciation accrual for Susquehanna should be used to mitigate stranded costs.

70. In late 1995, PP&L announced plans to reduce capital expenditures over a 5-year period by $671 million. Of this total, $486 million represented reductions in plant expenditures for fossil generating units. Reductions in capital investment in generating facilities mitigates PP&L's stranded costs. PP&L St. 2, p. 9.

71. Several parties have suggested that stranded costs should be shared between PP&L and its ratepayers by various means. *See, e.g.*, OCA St. 1, pp 29-32; OTS St. 1, pp. 20-21; PPLICA St. 1, pp. 15-22. The parties' proposals that the Commission disallow recovery of a portion of PP&L's stranded costs are based on an incorrect interpretation of Section 2804(13) of the Act which provides:

> Consistent with Section 2808 (relating to competitive transition charges), the commission has the power and duty to approve a competitive transition charge for the recovery of transition or stranded costs it determines to be just and reasonable to recover from ratepayers.

72. The parties "sharing" proposals also are at odds with prior regulatory practice. In previous years, parties in prior utility base-rate proceedings have contended that certain otherwise "just and reasonable" expenses of public utilities should be "shared" between ratepayers and the utility on policy grounds similar to contentions raised by various parties in this proceeding. These contentions have been uniformly rejected by Pennsylvania appellate courts. *See, e.g., Butler Township Water Co. v. Pa. P.U.C.*, 81 Pa. Cmwlth. 40, 473 A.2d 219, 221-22 (1984); *T.W. Phillips Gas & Oil Co. v. Pa. P.U.C.*, 81 Pa. Cmwlth. 205, 474 A.2d 355, 366-67 (1984).

73. The General Assembly has mandated "sharing" mechanisms elsewhere in the Public Utility Code. When considering electric generation units with excess capacity that is not used or useful in the public service or electric generating units which experience excessive outages, the General Assembly has set forth specific procedures for such determinations and specified the specific sharing mechanisms that the Commission is authorized to employ. *See* 66 Pa.C.S. § 1322 (as to excessive outages) and § 1323 (as to excess capacity). In contrast, the Act does not contain any provision requiring a "sharing mechanism."

74. The parties' sharing proposals ignore the fact that virtually all of PP&L's plant investments have been reviewed by the Commission in prior base-rate cases and included in rate base as being prudently-incurred and used or useful in the public service. PP&L's most recent base-rate case was based upon a future test year ended September 30, 1995. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, p. 1 (September 27, 1995). No generation units have been placed in service since this base-rate case. Only the relatively minor plant additions placed into service since September 30, 1995, could even be the subject of prudence contentions in this proceeding, and no such contentions have been raised. Therefore, all of PP&L's rate base and PP&L's expenses, as of September 30, 1995, have been determined to be "just and reasonable" as that term is used in Section 1301 of the Public Utility Code, 66 Pa.C.S. A. § 1301, to establish a utility's rates.

75. In the PECO Restructuring case, the Commission ruled that in determining a joint and reasonable level of stranded cost recovery under Section 2808(c)(3), the Commission must consider whether "the utility's efforts to mitigate stranded investment have been "reasonable under all of the circumstances," PECO at 67 (citing Section 2808(c)(4). The Commission noted that Section 2808(c)(4) requires "equal consideration" of the utility's "efforts undertaken over time . . . to reduce or moderate rate levels." With some of the lowest rates in the state, PP&L has satisfied the standard. Indeed, it is this application of

the rate cap to those low rates that prevents PP&L from recovering up to $500 million in stranded costs. This is more than sufficient to satisfy any notion of sharing even if one existed in the Act.

76. Any sharing proposals also should be viewed in context of the financial effect on the utility and its ability to provide safe and reliable service. The OCA's proposed stranded cost proposal would have a devastating impact on PP&L. To demonstrate the importance of allowing PP&L to recover its stranded costs, PP&L prepared a financial analysis comparing the effects of PP&L's recovery of approximately $4 billion of stranded costs with the results that would occur under OCA's initial proposed allowance of one tenth the level of stranded costs proposed by PP&L, or $0.4 billion. This analysis is provided in PP&L St. 8-R, pp. 18-29.

77. The starting point of this analysis was PP&L's results of operations for 1996. PP&L then brought forward the results of operations for 1996 to 1999, when a substantial portion (one third) of PP&L's customers will have access to the competitive generation market. Using PP&L's simplified approach, the pro forma return on equity for 1999, under PP&L's proposal, would be 10.52%. PP&L St. 8-R, p. 23.

78. OCA's proposal of a 32% rate reduction would produce sharply different results. Under OCA's proposal, PP&L's 1999 *pro forma* return on equity would be a *negative* 9.65%. PP&L would experience an operating loss each and every year of the transition period. Under OCA's proposal, PP&L would be unable to pay dividends or interest on debt. If OCA's proposal were adopted, PP&L's ability to maintain the transmission and distribution portion of its business would be endangered. PP&L's ability to be the supplier of last resort, to obtain credit, and to maintain adequate system reliability all would be compromised. PP&L St. 8-R, pp. 24-27.

79. The above financial analyses were calculated using PP&L's projected market price of electric generation. If PP&L's projections are accurate and if OCA's proposals were to be accepted, the result would be devastating for PP&L, its investors and those who rely on its service. If, however, the market price of electric generation turns out to be greater than projected by PP&L, as projected by OCA, ratepayers nevertheless are protected by the rate caps. They would not be required to pay more than they do presently.

80. OCA's proposed level of stranded costs is unjustified and does not represent a reasonable even-handed sharing of risks associated with stranded costs.

III. STRANDED COST CALCULATION METHODOLOGY

81. The Act generally identifies three categories of stranded costs: (1) regulatory assets and other deferred charges, the unfunded portion of nuclear plant decommissioning costs, and cost obligations under contracts with non-utility generators ("NUGs"); (2) costs related to

the cancellation, buyout, buydown or renegotiation of NUG power supply contracts; and (3) generation-related expenses. 66 Pa.C.S. §2803.

82. PP&L's Restructuring Plan filing includes expenses from each of the categories identified by the Act. Specifically, the Company's filing includes: (1) regulatory assets and other deferred charges typically recoverable under traditional cost-of-service regulation, and cost obligations under Commission-approved contracts with NUGs; (2) prudently-incurred costs related to the cancellation, buyout, buydown or renegotiation of NUG contracts; and (3) net investments and operating expenses associated with existing generation facilities, disposal of spent nuclear fuel, decommissioning costs associated with existing generation facilities, and other stranded costs, including severance, early retirement, outplacement and related costs for employees who are affected by changes anticipated as a result of the transition to full competition under the Act. PP&L St. 8, p. 3.

83. For stranded cost calculation purposes, PP&L divided its claimed expenses into four categories: (1) nuclear generation; (2) fossil generation; (3) NUGs; and (4) generation-related regulatory assets. Utilizing a regulatory or revenue requirement methodology (the "regulatory method"), PP&L determined that it has approximately $4.5 billion in stranded costs after mitigation.[2/]

84. The OCA and PPLICA oppose the Company's method of calculating stranded costs related to generating plant, and recommend that the Commission adopt the asset value method proposed by PECO Energy Company in its current Restructuring Plan proceeding (Docket No. R-00973953). OCA St. 1, p. 14; PPLICA St. 2, p. 10. The OCA and PPLICA, however, propose to calculate stranded costs associated with regulatory assets using the regulatory method.

85. The regulatory method of calculating nuclear and fossil generating plant stranded costs compares the annual revenue requirements for each generating plant to the projected annual revenues each plant would receive from the sale of its output using market-based prices for each year beginning January 1, 1999, to the end of its remaining service life. PP&L St. 8, p. 4. The Company then applied a PUC-jurisdictional percentage to the annual excess or deficiency, and discounted the resulting stream of annual excesses or deficiencies to present value at January 1, 1999 using a discount rate of 7.92%, which is PP&L's after-tax weighted average cost of capital. PP&L St. 8, p. 4; PP&L Exh. JRS 1, p. 1.

2/ In its initial filing, PP&L estimated that it had approximately $4.6 billion in stranded costs. PP&L Ex. JRS 1, p. 1. The Company subsequently revised its claim to reflect an error on its original calculation.

86. The asset value method compares the present value of revenues, less cash expenses, that could be earned from generating facilities in a competitive market, with the sum of the current book value of generation and regulatory assets. Cash expenses include any above-market costs that will be incurred under power purchased agreements with NUGs. PP&L St. 8-R, p. 7.

87. Several considerations favor the regulatory method (PP&L St. 8-R, pp. 5-7; PP&L St. 19-R, pp. 15-16):

1. The regulatory method is simple to understand and to apply because it essentially uses a series of future test years, a concept familiar to the Commission. All revenues and expenses are reflected in the time period in which they occur.

2. A variety of conceptual issues arising under the regulatory method -- e.g., the treatment of income taxes -- previously have been resolved by the Commission under traditional cost-of-service regulation. Thus, the regulatory method allows the Commission to apply existing rules and accepted assumptions in calculating stranded costs.

3. The regulatory method is fully consistent with the Act. Specifically, Section 2803 of the Act defines stranded costs as the "known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, *which traditionally would be recoverable* in a competitive generation market and which the commission determines will remain following mitigation by the electric utility." 66 Pa.C.S. §2803. Under traditional rate regulation, utilities are allowed a fair opportunity to recover revenue requirement. Consequently, revenue requirement is the proper starting point for the determination of stranded costs of generating plants. Thus, the Act defines stranded costs based on a comparison of revenue requirements under traditional regulation with revenues projected in a competitive market. The regulatory method properly implements this statutory approach.

4. The regulatory method prevents an electric utility from deriving an unfair benefit from the transition to competition. The regulatory method is designed to ensure that, at most, a utility may only receive the level of revenues that it would have received under current Commission-approved rates.

5. The regulatory method takes into account the effects of book value on revenue requirements year by year. Therefore, the specific complexities and effects of book value, e.g., changing jurisdictional allocation factors and deferred taxes, can be considered fully under the regulatory method. As explained by PP&L witness Guth, the asset value method merely "glosses" over such complexities because "there is no particular economic meaning to a relationship between, on the one hand, book value based upon accounting conventions for depreciation and, on the other, market value that a willing buyer would offer a willing seller in an arms length transaction." PP&L St. 19-R, p. 15.

88. Application of the asset value approach presents numerous problems and complexities. For example, the asset value method simply cannot be used to calculate the regulatory assets. OCA and PPLICA recognize this shortcoming and purport to use the revenue requirement method for regulatory assets, while retaining the asset value method for plant assets. The result is a mixed, hybrid approach which introduces substantial (and needless) complexities and causes serious errors in the OCA and PPLICA presentations.

89. The Commission's recent Order in the PECO Restructuring proceeding (Docket No. R-00973953) includes a footnote which states as follows (PECO Order, p. 80, note 71):

> We agree with PAIEUG witness Falkenberg that a "lost revenues" approach to stranded cost recovery is inappropriate. He notes that even under traditional regulations, a utility never had the expectation of guaranteed future revenues. Instead, traditional regulation sought to provide a reasonable opportunity to earn a just and reasonable return on investment. While future revenues are an important component of the future value of utility generation assets, they do not directly determine the amount of recoverable stranded utility plant.

90. The PECO Order does not require the use of the asset value method in this case. First, it is important to note that, when properly applied, both the regulatory and asset value methods should produce comparable results because they theoretically measure the same costs. PP&L St. 19-R, pp. 9-14. Problems arise from the parties' application of the asset value method and the erroneous and inconsistent assumptions used, not with the asset value method itself. Second, the regulatory method was not at issue in the PECO Restructuring case. The Commission's brief mention of the regulatory method in the PECO Order is dicta. Third, the OCA and PPLICA stranded cost models are not in the record in this case. Thus, the record evidence simply does not include the information necessary to calculate stranded costs or to make any adjustments to such calculations. In

contrast, PP&L's complete regulatory methodology is in the record and is readily available to all parties and the Commission.

91. Application of the asset value model is problematic here because it is not in the record. Therefore, to assist the ALJ and the PUC, PP&L has included a series of tables to provide a consistent application of the asset value model and a full reconciliation of the model with PP&L's preferred revenue requirements model. These tables were prepared from data in the record, although some calculations are not part of the formal record. PP&L believes, however, that this information is an essential tool to the ALJ and the PUC and is critical to a complete and fair determination of stranded costs in this proceeding.

92. For these reasons, PP&L's stranded costs should be calculated using the revenue requirements method.

93. Tables B to D provide a summary of PP&L's $4.5 billion stranded cost claim under the regulatory method. Table B provides the same calculation using the revenue requirements method. Table C provides a summary of OCA's proposal under the asset value method. Finally, Table D provides a reconciliation of the differences between the PP&L and OCA proposals using the asset value method. If the PUC elects to use the asset value method, Table D should be used to derive the value of any adjustments. Changing one item may have secondary effects on other figures which would have to be reconciled in the Company's compliance filing.

IV. MARKET PRICE OF ELECTRICITY

94. The forecast of prospective market prices of electricity is the critical first step in determining the competitive market value of PP&L's generating assets. These electricity prices are used to develop revenues for each plant on an annual basis. The revenues are then used to determine the stranded costs of the generating plants.

95. The prospective market prices for electricity are comprised of two components: The price of capacity and the price of energy. Customers will pay for the right to draw upon PP&L's generating assets when needed. These are payments for capacity. Customers also will pay for electric energy as they use it. These are payments for energy. While both energy and capacity prices are important in evaluating the competitive market value of PP&L's generating assets, energy prices are far more significant because they will represent approximately 90% of revenues received for electricity.

96. Three witnesses in this proceeding have estimated prospective market prices for electricity (S. Jones for PP&L, D. Smith for OCA and R. Falkenberg for PPLICA). Each witness has provided an estimate of future capacity and energy prices.

97. Dr. Jones defined the supply side of the market as the generation sources in PJM and those available to serve customers in PJM. This definition includes both power sources in PJM as well as energy and capacity that can be delivered to PJM. PP&L St. No. 7, p. 9. The demand side of the market for generation includes all customers in PJM as well as those with access to electricity that can be delivered over lines within and connected to PJM. PP&L St. No. 7, p. 9. Dr. Jones' proposed relevant market was not opposed and is adopted for purposes of this proceeding.

98. Dr. Jones estimated future capacity prices by beginning with current contracts for sale of capacity held by PP&L. PP&L currently makes short-term or spot capacity sales and makes sales in the forward market. PP&L St. No. 7, p. 45.

99. In forecasting future capacity prices Dr. Jones projected that capacity prices would rise sharply as PJM moved from the current state of capacity excess to a balance of demand for, and supply of, capacity. For example, as shown on Exhibit STJ-8 Dr. Jones' forecasted capacity price rises from $22/Kw in 1999 to $50/Kw in 2002. This rise in price corresponds to an expected elimination of the capacity excess in PJM. As explained by Dr. Jones, it is reasonable to expect that capacity prices will rise sharply as the shortage builds and that prices will drop back somewhat as new capacity is installed and customers react to higher capacity prices by switching from firm to interruptible service in response to the higher capacity prices. PP&L St. No. 7, p. 45-46. This is one of the many effects of a competitive market which must be anticipated in accurately reflecting future market prices.

100. OCA's witness Mr. Smith, projects continually increasing capacity prices from 1999 to 2015. OCA St. No. 2, Ex. No. DCS-7; OCA St. No. 2-S, Ex. No. DCS-10. Mr. Falkenberg, PPLICA's witness, projects generally rising capacity prices with a two year reduction in prices following tightening of the capacity market in 2001. PPLICA St. No. 2-S, Ex. No. RJF-9-b.

101. OCA, PPLICA and OSBA challenged Dr. Jones' forecast of market capacity prices as insufficient to support addition of new capacity. OCA St. No. 2, pp. 12-17; PPLICA St. No. 2, pp. 35-40; OSBA St. No. 1, pp. 32-34.

102. Parties have raised several factors to be considered in evaluating whether capacity prices and energy prices are sufficient to support construction of new capacity. These factors are the cost of the new unit, costs of other facilities such as land and pipelines to serve the unit, and the heat rate (amount of BTUs needed to produce a kWh of electric energy) at which the unit can be expected to operate.

103. In order to address the parties' concern, Dr. Jones presented, in rejoinder, revised Ex. Nos. STJ-28 R, STJ-28aR and STJ-28bR. The revised Ex. No. STJ-28R summarizes the rates of return that would be produced at Dr. Jones' capacity and energy prices for

combined cycle units. In each case, the rate of return exceeds 12.8% and in all but one case, exceeds 13%. PP&L Ex. STJ-28R demonstrates that Dr. Jones projected market prices are sufficient to support the installation of new capacity.

104. Dr. Jones also presented, as part of his rejoinder testimony, Ex. No. STJ-32. This exhibit is designed to show the return that will be produced by Dr. Jones' prices applied to Mr. Smith's estimate of combined cycle unit costs. The second column of this exhibit shows Mr. Smith's estimated installed costs of a combined cycle unit. Applying Dr. Jones' energy and capacity prices, for the time period when a combined cycle unit would run, to Mr. Smith's unit costs, without adjustment, produces a 13.14% rate of return (Tr 1409). Thus, even accepting Mr. Smith's estimate of unit costs, Dr. Jones' energy and capacity prices are more than sufficient to produce an adequate return and to justify installation of new capacity.

105. The third column of PP&L Ex. No. STJ-32 makes adjustments to the unit costs estimated by Mr. Smith to correct the errors in Mr. Smith's analysis. First, it eliminates the interest during construction cost because this amount, as agreed to by Mr. Smith on cross examination, is accounted for when using a net present value calculation (Tr 1529). Second, it also eliminates Mr. Smith's erroneous gross up of land, infrastructure and gas pipeline costs to reflect the effects of the lower summer capacity rating of the unit. As explained by Dr. Jones, these costs are fixed and are not affected by decreases in capacity in the summer (Tr 1395). When these corrections are reflected, PP&L Ex. STJ-32 demonstrates that Dr. Jones' prices would be sufficient to generate a 13.87% rate of return on the corrected unit costs. This return rate is significantly above that which any party would contend is necessary to generate capacity additions.

106. The contentions of various parties that Dr. Jones' market capacity prices are "insufficient" to support additions of new capacity are unsupported by the record. The above analysis demonstrates that PP&L's forecasted prices are sufficient to support such additions at even today's costs and heat rates. As unit costs decrease and/or heat rates improve (less fuel to produce each kWh) the rates of return produced by new units will be even higher. Accordingly, the market capacity prices forecasted by Dr. Jones are demonstrated to be reasonable.

107. The higher capacity and energy prices projected by Messrs. Smith and Falkenberg indicate that investors in new generation will achieve rates of return well in excess of the 13.14% to 13.87% shown in PP&L Ex. STJ-32. Neither witness has provided an explanation why investors will demand capacity prices that will produce returns in excess of 14%. It is not credible to believe that investors will demand capacity prices that will produce returns in excess of 14% in an environment where there are competing projects.

108. Each of the witnesses testifying as to energy prices used a different model to project such prices. Dr. Jones, testifying for PP&L, used the EGEAS (Economic Generation

Expansion Analysis System) model. Dr. Jones explained how the EGEAS model operates:

> EGEAS is an economic dispatch model designed primarily for long-term system planning. As its name implies, the primary purpose of the model is to find the best possible combination of generation resources for meeting system load in the short run and in the long run. In the short run, EGEAS is a production cost model, dispatching units to meet demand levels in each hour of the year. Over the long run, the model adds capacity to the existing system to meet reliability constraints. Depending upon the economics at that point in time a new unit will be added, either peaking or combined-cycle technology is added to minimize cost.
> PP&L St. No. 7, p. 25.

109. The EGEAS model has been used to dispatch units on the PJM system. It is not, therefore, a theoretical model but one which has been tested in the real world environment (Tr 1685-1686). Furthermore, the EGEAS model is publicly available. PP&L St. No. 20-R, pp. 19-21.

110. The model employed by PPLICA's witness, Mr. Falkenberg, is a theoretical model and is proprietary to his firm. It was not made available to PP&L until one week after PP&L's rebuttal testimony was filed in this proceeding (Tr 1676).

111. The numerous deficiencies in the Falkenberg model are explained in PP&L witness Falk's testimony. PP&L St. No. 20-R. However, the problem that is common to all of the defects was explained by Mr. Falk as follows:

> The entire raison d'étre for competitive markets is their ability to minimize costs to meet a given level of demand. . . Whenever a production costs simulation produces costs higher then those which are optimal, the result is to overstate what an efficient competitive market could have produced.
>
> * * *
>
> Mr. Falkenberg has cut many corners in his model. These cut corners generally produce results, as I shall demonstrate, which do not minimize costs to meet a given load. As a result, they produce higher aggregate prices than a competitive market would.

112. Mr. Falk identified five areas in which Mr. Falkenberg's model did not optimize costs. They are: 1) maintenance scheduling; 2) scheduling of capacity additions; 3) scheduling of repowering of existing units; 4) calculation of unserved energy, and 5) size of units.

These deficiencies cause Mr. Falkenberg's model to overstate market prices and understate stranded costs.

113. Mr. Falkenberg's model has not been tested in the real world of energy dispatch and is a proprietary model that was not made available to even the parties in this proceeding until after the filing of rebuttal. The over simplifications and the lack of independent real world application of the model make it unreliable for the purposes of forecasting market prices.

114. OCA's witness, D. Smith, used the ENPRO model to forecast energy prices. This model is less problematic than the Falkenberg model for two reasons. First, it is an operational dispatch model like EGEAS, not a theoretical model like the Falkenberg model. Second, ENPRO is commercially available, and, therefore can be obtained and run by any participant in this proceeding.

115. The primary deficiency of the ENPRO model is that it can model only 200 units (Tr 1398). In order to provide room for the addition of new units, Mr. Smith could model less than 200 of the 350 existing units in PJM (Tr 1398, 1511). To accomplish this, Mr. Smith had to aggregate existing units or treat them as one unit (Tr 1511). The problem with aggregating units is that it raises energy prices by using the average cost of the aggregate group rather than the lowest cost at all times.

116. A second deficiency is in Mr. Smith's application of ENPRO. As explained by Dr. Jones, Mr. Smith simply assumes that units which can be fired with either oil or gas will use oil one half of the time and gas the other half of the time, regardless of competing fuel prices. This is a problem, particularly where oil prices, as in Mr. Smith's fuel price forecast, rise faster than gas prices. This assumption is unrealistic and biases electricity prices upward since dual fuel units can be presumed to use the lower price fuel (Tr 1397-1398).

117. Finally, Mr. Smith reduces the availability of imports from outside PJM after 2005, without explanation or justification. (Tr. 1398). Because imports from the west generally are at lower costs (Tr 1510) this increases the price of electricity in PJM just as the 7-year rate cap under the Act expires.

118. Dr. Jones presented Ex. STJ-33 to graphically illustrate the effects of these deficiencies in the ENPRO model. As shown by the differences between the blue and green lines on PP&L Exhibit STJ-33, correction of these errors in ENPRO reduces Mr. Smith's forecasted market prices for energy by about $3/Mwh for years 2007 through 2015, with a somewhat lesser effect in earlier years.

119. The EGEAS model, in contrast, does not contain the methodological problems identified by PP&L with regard to the Falkenberg model and ENPRO. Specifically, EGEAS is a

dispatch model which has been used for many years in dispatching units on the PJM system.

120. The EGEAS model can model all of the units in PJM as well as necessary additions, it schedules maintenance rather than spreading it arbitrarily throughout the non-summer months, it optimizes new capacity additions to produce the lowest energy costs by choosing between combustion turbine and combined cycle units, it uses appropriate prices for unserved energy and it properly reflects different summer and winter capacity ratings. PP&L St. No. 20-R, p. 18. It is the superior model and the real world has determined that it reflects actual conditions on PJM.

121. The only criticism which other parties have directed at the use of the EGEAS model concerns the treatment of start up or no load costs.

122. OCA's Mr. Smith and PPLICA's witness Mr. Falkenberg state that generators would not bid their incremental cost of generation because there are extra costs attributable to start-up that would not be recovered if they happen to be the unit that supplied the last kWh of energy at that point in time. In this way, intervenors argue that PP&L has understated the market clearing price of energy. OCA's Smith at 5. Their reasoning is that the incremental cost of some blocks of a unit is below the actual cost of operation at certain loads. Intervenors argue that the only way to account for this reluctance would be to assume that generators adjust upward their initial bids to the average cost of generation (supposing that the average costs of generation always exceeds the incremental cost of generation), because no generator would knowingly bid his incremental cost into the market for fear of losing money on an on-going basis. In the view of at least one of the intervenors (Falkenberg at 18), the average full load heat rate would be bid by the generator assuming that the *single heat rate* for each unit was equal to the average full load heat rate.

123. There are two major flaws in intervenors' contention about this "heat rate" issue. First, intervenors incorrectly assume that any individual generator subject to competition would somehow know, in advance and for any hour of the year, exactly when the market for energy would clear at the incremental cost of their unit. Only in this way would the potential cost of not offering capacity to the market offset the financial loss of foregoing the opportunity to earn a profit on that capacity because as long as the supply curve for energy has the usual upward slope, all generators but the last unit dispatched at any point in time will receive a price for that hour that is in excess of their incremental cost.

124. Second, whether or not intervenors' allegation is valid is (a) an empirical question requiring proof and, (b) has to recognize that EGEAS does not dispatch an entire unit on the basis of a single heat rate. Rather, in a manner like the way PJM actually dispatches the system, EGEAS divides a generator's capacity into several blocks, each with a different heat rate. At some points in time, the incremental cost of energy based on heat

rates is greater than *and* less than the average cost of generation as shown in PP&L Exhibit STJ-22.

125. Even if generators could know in advance that their bids to supply energy would represent the market clearing price and, therefore, adjusted such bids to cover so called "no load" costs, the effect on PP&L's generation revenues would be sufficient to reduce PP&L's stranded costs by only $37 million out of $4.5 billion or about eight tenths of a percent. PP&L St. 7, p. 15.

126. Either the EGEAS model or the ENPRO model, with certain corrections, can be used to forecast energy prices. The correct inputs to the model are, by far, the most critical issues in forecasting energy prices and differences in the inputs selected by each witness account for the majority of the differences between the forecasts of the witnesses.

127. Perhaps the most critical and significant input to the models is the cost of fuel to operate each unit that generates electricity. Since the energy price for all units running in a given hour equals the cost of operating the marginal cost unit operating in that hour, the variable cost of operating the marginal cost unit is critical. Fuel price is the primary component of variable cost.

128. A forecast of fuel prices must reflect the fundamentals of fuel markets. In particular, two concepts are extremely important. The first concept is that increases in fuel prices should be separated into two components: increases in *real* fuel prices (exclusive of inflation) and increases in fuel prices due to inflation. The combination of the increase in the real fuel price and the effect of inflation on the fuel price produces the nominal fuel price at any point in time.

129. The second concept is that projected increases in one fuel price, such as natural gas, must be reviewed in the context of competing fuels such as oil and coal. Both common sense and experience demonstrate that prices of competing fuels move in tandem and forecasts which project different rates of increase for competing fuels are highly suspect.

130. Dr. Jones forecasted that 1996 real fuel prices would remain flat until 1999. Dr. Jones then forecasted that real fuel prices would remain flat and would increase by the increase in inflation from 1999 forward. PP&L St. No. 7-R, p. 41.

131. Dr. Jones projected that real fuel prices would remain flat after 1999 because history demonstrates that real fuel prices rise and fall but revert to a mean price of about $15.50 in 1996 dollars over the long term. PP&L St. No. 7-R, p. 47. As shown in Dr. Jones' Ex. No. STJ-16, oil prices averaged about $15.50 a barrel (in 1996 dollars) over the period 1900 to 1996 excluding the unusual period of 1979 to 1985 represented by the Iranian Revolution. Nevertheless, Dr. Jones adopted a real oil price of $18.00 per barrel (Ex.

No. STJ-16), which corresponds to the average price of $17.90/Bbl over the last 10 years. PP&L St. No. 7-R, p. 54.

132. Only Mr. Knecht, on behalf of OSBA, attempted to refute Dr. Jones' explanation that real prices are mean reverting, by calculating a .8% rate of increase in the price of oil from 1939 to 1996. OSBA St. No. 51, pp. 17-22, Ex. No. RDK-S-2. However, Dr. Jones explained in rejoinder that the choice of a particular starting year substantially effects this type of calculation. If Mr. Knecht had chosen any of 24 differing starting points since 1900 there would have been real declines in oil prices and, if many other starting years were used, real oil prices would simply be flat (Tr 1404-1405). As a result, choosing a starting point year near the end of a depression when oil prices were low fails to provide any useful information about the long term trend of real oil prices.

133. Projections of rising real fuel prices are contrary to both the weight of historic evidence and the progress of technological developments in exploration for fuels (Tr. 1405-1406).

134. Messrs. Falkenberg (PPLICA) and Smith (OCA) rely on the forecasts prepared by DRI and EIA respectively. By increasing nominal fuel prices more than their projected increases in inflation, these forecasts effectively project both increases in real fuel prices and increases in fuel prices due to inflation. PP&L St. No. 7-R, p. 55; Tr 1404.

135. Neither witness has presented any substantive basis for concluding that real fuel prices will rise. In this regard, it is to be noted that Dr. Jones' real oil price of $18.00/Bbl is essentially equal to the $17.90/Bbl average price over the last 10 years and is significantly above the $15.50/Bbl average long-term price of oil in 1996 dollars excluding years affected by the Iranian Revolution. PP&L St. No. 7-R, p. 54. Accordingly, Dr. Jones' projection of real oil prices is on the high side of average historical prices.

136. Furthermore, as shown on PP&L Ex. STJ-18, one standard deviation around this average price establishes a range of $12/Bbl to $19/Bbl. While oil prices may rise and fall above the average it is reasonable to conclude that they only rarely will move outside one standard deviation. As also shown on PP&L Exhibit STJ-18, in contrast to Dr. Jones' real oil price of $18/Bbl, Mr. Falkenberg's (EIA's) real oil prices begins at about $19/Bbl and continually rises throughout the forecast period to prices of about $24/Bbl, well outside one standard deviation from the average price. The DRI forecast used by OCA produces similar results (Ex. No. STJ-19). Accordingly, the expectation of these forecasts -- that real oil prices will rise -- is not supportable given historic trends. Equally important, neither OCA's or PPLICA's witnesses has presented any evidence to support such real price rises, they have simply accepted the DRI and EIA forecasts.

137. The witnesses' use of the DRI and EIA fuel prices is inappropriate given that both entities have continually over-estimated fuel prices. As shown on PP&L Ex. STJ-14a and 14b,

each of EIA's 1986, 1987, 1989 and 1992 long term fuel price forecasts has consistently overstated fuel prices. DRI's fuel price forecasts closely matches EIA's over-estimates (Ex. STJ-19). As shown on PP&L Exhibit STJ-35, DRI's 1994 and 1995 forecasts also overstated inflation and, thereby fuel prices.

138. As shown in PP&L Ex. STJ-21, the DRI 96 forecast begins with average inflation rates of 2.3 for 1997-2000, but then increases inflation rates to a level of 3.5%, on average, for the period 2005-2015. OCA's Mr. Smith revised his forecast to reflect the updated DRI Spring 1997 Outlook (Tr. 1516-1517) and to correct a "starting point" problem Dr. Jones noted in his testimony (Ex. STJ-12). Even so, the updated Spring 1997 Outlook continues to use the much higher 3.5% average annual inflation rate for the period 2005-2010.

139. Mr. Falkenberg used the EIA forecast for 1997. As also shown in PP&L Exhibit STJ-21, the EIA forecast starts with inflation at 2.5% and raises it to 3.4 % on average for 2005-2010 and 3.6% on average for the period 2010-2015. As shown on PP&L Exhibit STJ-35, DRI has consistently over-estimated inflation in past forecasts. EIA forecasts match DRI's forecasts closely (Ex. STJ-19).

140. Neither Mr. Smith nor Mr. Falkenberg has offered any explanation why the inflation rates built into the DRI and EIA fuel forecasts escalate over time (Tr 1403). These inflation forecasts are from the DRI and EIA fuel price forecasts. Despite reliance on these forecasts neither witness even obtained the full source documents for these forecasts or analyzed the bases used in these forecasts to estimate inflation (Tr 1517-1518, Tr 1750). Accordingly, they have not examined the bases for these forecasts. Forecasts of inflation which rise over time are simply inconsistent with federal reserve policies observed over the last decade (Tr 1400). There is no basis, on this record, to justify the use of the EIA and DRI inflation estimates and the record demonstrates that their forecasts have consistently overstated inflation.

141. The rising rates of inflation combined with rising real oil prices projected by these parties create what Dr. Jones referred to as the "dog leg" problem. The DRI and EIA forecasts initially project gradual rises in fuel prices but as the higher inflation rates and increases in real fuel prices "kick in," nominal fuel prices rise sharply. As shown graphically in PP&L Ex. Nos. STJ 14a and b, the fuel price curve slopes upward in the shape of a dog leg. There is no precedent in history for such an effect (PP&L St. No. 7-R, p. 42) and, in past forecasts, this phenomenon accounts, in part, for DRI's and EIA's confirmed over-forecast of fuel prices (PP&L Ex. No. STJ-14a and b).

142. In addition to the errors of improperly rising real fuel prices and increasing inflation rates, the EIA and DRI forecasts project a divergence between the real prices of oil and gas versus the real price of coal.

143. The divergence of gas and oil prices from coal and uranium prices is both illogical and unprecedented for competing fuels. As demonstrated by Dr. Jones in Ex. STJ-16a, real prices of competing fuels are highly correlated over the 15 year period of 1981-1995. In other words, the prices of these fuels move up and down together. If the price of one competing fuel rose sharply and others did not move upward, there would be fuel switching in many applications (PP&L St. No. 7-R, pp. 47-49). This is particularly the case for gas and oil versus coal. As also shown in PP&L Ex. No. STJ-16a, Dr. Jones's forecasts of the prices of each type of fuel are highly correlated. On the other hand, the fuel price projections of DRI and EIA show a significant, and historically unprecedented, divergence of oil and gas prices from the price of coal.

144. The "divergence" problem is particularly critical to the issues of stranded costs in this proceeding. The marginal cost units operating on PJM will normally be gas and oil fuel units, and these units will set the price for all units operating in the same hour. OCA and PPLICA understate the costs of operating PP&L's coal generating units by assuming coal prices that are inconsistent with oil and gas prices used in their models. The result is an understatement of stranded costs associated with these units.

145. Even if the DRI gas and oil prices were accepted, the Commission must, at a minimum, adjust upward the coal prices assumed by DRI. To do otherwise is not only contrary to the record but would punish PP&L for owning and operating coal plants that have produced low cost electricity for many years.

146. PP&L has submitted a recalculation of its stranded costs which, among other things, uses prices for coal that escalate in a manner that is consistent with DRI's escalation of oil and gas prices. Correction of this divergence problem alone would create an increase in stranded costs of approximately $230.157 million.

147. The evidence shows that the DRI and EIA fuel price forecasts are overstated. These overstated fuel prices result in a significant overstatement of energy prices forecasted in Mr. Smith's (OCA) ENPRO model and Mr. Falkenberg's (PPLICA) model.

148. The forecast of inflation is significant because it affects fuel prices and because inflation is used to escalate other costs that are used in each of the models to derive market prices of electricity. In particular, variable O&M costs must be projected for each of the units that will be operated. Each of the witnesses applies an expected inflation rate to current levels of variable O&M costs to derive future O&M costs.

149. There are two issues with regard to the projection of inflation. The first is what measure of inflation should be used. The second is the year by year amount of inflation.

150. With regard to the proper measure of inflation, Dr. Jones explained that the Consumer Price Index (CPI) is clearly overstated as to costs faced by PP&L because it relates to

consumer products and not to items that affect PP&L's generating costs. While the Gross Domestic Product (GDP) deflator is a better indicator of the effect of inflation on such costs, this measure includes long-lived assets as if they were purchased monthly. Dr. Jones, therefore, concluded that the Producer Price Index (PPI), which measures prices received by industrial firms for goods they produce is the best indicator of costs to be incurred by PP&L. PP&L St. No. 7-R, pp. 60-61. Dr. Jones estimated average future inflation at 2.5%. PP&L St. No. 7, p. 40, PP&L St. No. 7-R, p. 61.

151. OCA's and PPLICA's witnesses did not evaluate the proper measure of inflation or attempt to estimate inflation. OCA and PPLICA simply adopted the rising inflation rates contained in the DRI and EIA forecasts (Tr 1401-1402). OCA and PPLICA can not explain the basis for these increasing inflation estimates because they merely accepted the numbers in the fuel price forecasts.

152. The OCA's and PPLICA's continually rising inflation assumption is completely inconsistent with federal monetary policy and the projections of other professional forecasters (Tr. 1400-1401).

153. PP&L's proposed steady 2.5% inflation rate is consistent with current experience and modern monetary policy, and provides a reasonable inflation projection for use in this proceeding.

154. PP&L forecasted electricity demand for PJM by adopting the most recent forecast of demand compiled by PJM. Updates for demand on PP&L's system through December 1996 were reflected. PP&L St. No. 7, p. 44. PP&L estimated demand growth of about 1.5% annually. No party has raised any issue with regard to forecasted demand.

155. The efficiency of new units also effects energy prices. In the EGEAS model, Dr. Jones made a very conservative estimate of the fuel consumption of new combined cycle and combustion turbine units. He assumed that a combined cycle unit would require 7000 BTUs of energy to produce a kWh and that a combustion turbine would require 10,200 BTUs to produce a kWh (Ex. No. STJ-5). These assumptions are conservative. For example, many existing combined cycle units already can produce one kWh at lower BTU levels (*i.e.* lower heat rates) (STJ-28R). Reflection of these lower actual heat rates in EGEAS would have resulted in lower energy prices and higher stranded costs because it would take less fuel to produce each kWh of energy from new units. No party has challenged the reasonableness of the efficiency assumptions used in EGEAS to project energy prices (Tr 1392).

156. Nuclear capacity factor refers to the percentage of the time that base load nuclear units will be operating. The use of a nuclear capacity factor that is too low in the models raises marginal energy prices by requiring other units with higher variable costs to operate. If actual nuclear capacity factors turn out to be higher than reflected in the models, actual energy costs will be lower than projected by the models.

157. Dr. Jones employed a forecasted 78% nuclear capacity factor in the EGEAS model based upon a study of actual unit availability factors in PJM and other systems. PP&L St. No. 7, p. 30. The data used to calculate availability is provided in Ex. STJ-6.

158. Mr. Smith used a 75% annual capacity factor. OCA St. No. 2, p. 21.

159. The availability of nuclear units has been steadily increasing and is projected to increase further. PP&L Exhibit STJ-30 shows historical availability factors for nuclear units in the United States from 1982 to 1995. In that period, the availability factor has improved steadily from about 65 percent to nearly 80 percent. Mounting experience in operating nuclear units has led to better management practices and fewer forced outages. Moreover, NERC forecasts show that this trend is expected to continue. PP&L Exhibit STJ-30 plots forecasted capacity factors to 2006 (actual capacity data are shown from 1991 to 1996). NERC forecasts suggest availability factors of at least 85 percent should be expected for the next decade. Thus, 78 percent is a somewhat conservative estimate of future nuclear availability. . PP&L St. No. 7-R, pp. 106-107.

160. The record fully supports a 78% nuclear capacity factor recommended by Dr. Jones.

161. Another element in projecting generating costs is the variable Operation and Maintenance expenses (O&M) of each unit. Variable O&M expenses are those associated with the production of energy as contrasted with fixed O&M which are costs associated with maintaining plants ready to operate.

162. Dr. Jones forecasted variable O&M expenses by escalating current variable O&M costs for each plant. Dr. Jones explained that the experience in industries that have moved from regulation to competition is that O&M expenses increase, for a period of time, at rates that are less than the rate of inflation. For this reason, Dr. Jones selected escalation rates for variable O&M expenses of 2% for 1997-2000, 1.5% for 2001-2005 and 2.5% for 2006-2016 (Ex. STJ-4).

163. Dr. Jones explained that his projection is based on an examination of the trends in O&M costs in capital intensive industries beginning with the 1980's, a review of the recent restructuring that has taken place in the natural gas pipeline industry, and evidence and opinion from various industry and academic publications. All of this evidence suggests that variable O&M costs in parts of the industry may by rising slower than inflation for some time. PP&L St. No. 7, pp. 41-42.

164. OCA's and PPLICA's witnesses simply applied the inflation forecasts contained in the DRI and EIA fuel price forecasts to current levels of variable O&M costs.

165. There are two problems with the OCA's and PPLICA's approach. First, DRI and EIA have consistently overestimated inflation. OCA's and PPLICA's witnesses provide no explanation or justification for these groups continual, and never realized, projections of rising inflation. Second, neither witness has reflected the probable effects of competition on variable O&M costs. As explained by Dr. Jones and further illustrated in his rebuttal testimony (PP&L St. 7-R, pp. 22-25; Ex. No. STJ-9), competition in the rail, trucking, airline and natural gas industries has produced ". . . double digit decreases in prices and costs of production . . ." St. No. 7-R, p. 24.

166. Dr. Jones' projections of variable O&M costs are both reasonable and conservative in that they likely overstate costs given the proven effects of introducing competition in other industries.

167. Reserve requirements refer to the amount of capacity which is required above expected demand to serve unexpected contingencies such as an unplanned outage of a generating station.

168. PJM currently plans for a 20% reserve requirement. PP&L St. No. 7, p. 23. However, Dr. Jones concluded that competitive pressures will lower reserve requirements to 18%. PP&L St. No. 7, p. 24. Mr. Smith also assumed a going forward reserve requirement of 18% although he indicated that this might not be achieved by 2000. OCA St. No. 2, p. 18. PPLICA's witness did not address reserve requirements.

169. Reserve requirements affect energy prices by determining the timing of additions of new capacity. As new capacity is added marginal energy prices will generally decline because the new capacity is more efficient (less fuel or BTUs to produce each kWh). Thus, higher reserve requirements mean lower energy prices. Therefore, Dr. Jones' adoption of an 18% reserve requirement, as compared to the current 20%, increases energy prices and lowers stranded costs. If Dr. Jones had continued to employ a 20% requirement, it would have forced the model to add new efficient additions at an earlier date and energy prices would have been lowered. Accordingly, the 18% reserve requirement is conservative and properly and consistently reflects the future effects of competition.

170. In projecting energy prices it also is necessary to include certain environmental costs which will affect the cost of operating the marginal cost generating unit. As explained by Dr. Jones, the EGEAS model permits the input of costs of emission allowances as an adjustment to fuel price escalators.

171. Dr. Jones explained how EGEAS models SO_2 emission allowance as follows:

> The first step is to identify which units will be running when the region is not in compliance. EGEAS accomplishes this by checking the emission production rate against the annual emission limit input for each facility. Once the units are identified, then

> those units that are subject to emissions limits are assigned allowances sufficient to bring them into compliance. The cost of bringing those units into compliance is built into the fuel escalation rates for PJM. PP&L St. No. 7, p. 42.

172. To determine the emission allowances Dr. Jones reviewed the history of SO_2 allowance prices, which have steadily declined, and he reviewed forecasts of allowance prices. Dr. Jones adopted the ICF Kaiser low case estimates of allowance prices through 2000 and escalated those allowances by the 2.5% expected inflation rate which he applied to escalate other costs. PP&L St. No. 7, pp. 41-42.

173. Dr. Jones did not include NO_x allowances as a cost in developing energy prices because of the great uncertainties in the development of technology to reduce NO_x emissions, uncertainties as to the levels of controls required for NO_x, the fact that NO_x controls are applied only in the ozone period of May through September and the lack of a developed market for NO_x allowances. PP&L St. No. 7, pp. 43-44; PP&L St. No. 7-R, pp. 97-104.

174. OCA's witness, D. Smith, contended that NO_x emission allowances will increase energy prices by something less than $1/Mwh. He also argued that NO_x allowances would have a significant effect on PP&L's net revenues (OCA St. No. 2, p. 24) but he did not quantify such effect.

175. In rebuttal, Dr. Jones explained the history of declining SO_2 allowance prices and that the competitive market would similarly drive down NO_x compliance costs. Dr. Jones concluded that electricity prices would rise from about $.05/Mwh to $.30/Mwh as a result of NO_x emissions with the higher end of the range being experienced late in the transition period when NO_x standards tighten. Therefore, the combination of a minor price effect occurring late in the transition period has a very small effect due to the present value impact. PP&L St. No. 7-R, p. 102.

176. No party responded to Dr. Jones' rebuttal on NO_x emission costs. The evidence demonstrates that NO_x emission costs are not a relevant factor.

177. An additional input to energy price models is the output of Non Utility Generators (NUGs). There is a dispute among the parties concerning the capacity factor at which these units will operate. Dr. Jones used a 90% capacity factor based upon actual historic experience provided by Mr. Krall within PP&L's service territory. PP&L St. No. 7-R, p. 105.

178. OCA witness La Capra argues that PP&L has overstated NUG output by 10-15%. OCA St. No. 1, p. 10. However, as explained in Mr. Krall's rebuttal testimony, the NUG capacity factors used were those actually experienced for the 3-years 1994-1996 on PP&L's system. As Mr. Krall also explained, most NUGs have now been on line for

some time and early operation and start up issues have been resolved. Because there are strong incentives for high output created by payments on the basis of kWh output, these units are, and will remain, well maintained.

179. Based on the record evidence, it is reasonable to conclude that future output levels will equal or exceed recent historic levels. PP&L St. No. 10-R, p. 40. OCA has provided no reasonable basis to reject use of these actual capacity factors for NUGs.

180. Another element which was considered by Dr. Jones in forecasting the market price of energy is ancillary services. As Dr. Jones explained, the only ancillary service that affects the market price of energy is spinning reserves.

181. Dr. Jones explained that spinning reserves were reflected in the EGEAS model. . PP&L St. 7-R, p. 90. By including the spinning reserve units as units dispatched, EGEAS includes the effects of a spinning reserve requirement in its determination of hourly energy prices.

182. The revenues received from spinning reserve operators are likely to cover only the variable costs (start up and no load costs). Accordingly, such revenues will not reduce PP&L's stranded costs of generation because they will recover only variable costs and can contribute nothing toward recovery of fixed costs. PP&L St. No. 7-R, p. 89.

183. Although there are potentially other sources of revenues from ancillary services, these revenues will not affect market clearing prices for energy. Furthermore, the amounts of these revenues are not significant. As noted by Dr. Jones, revenues derived from payments for non-spinning reserves should be very small given the large amount of capacity on PJM and the relatively small non-spinning reserve requirement. PP&L St. No. 7-R, p. 91. Similarly, frequency and voltage regulation will be provided at cost and would produce no contribution to fixed or stranded costs. PP&L St. No. 7-R, p. 92.

184. Dr. Jones demonstrated in rebuttal that the effects of ancillary services on market clearing energy prices have been properly reflected in the EGEAS model. OCA provided no response in surrebuttal. Therefore, there is no remaining issue.

185. One other issue raised by other parties concerns the effects on market clearing energy prices that would be created if there were an earlier than expected retirement of a generating plant.

186. Dr. Jones used projected retirement dates provided by Mr. Krall in PP&L St. No. 3-R. These dates reflect the retirement dates reflected in PP&L's last base-rate proceeding and are the dates reflected in PP&L's current depreciation rates. PP&L St. No. 7-R, p. 87.

187. OSBA's witness Mr. Knecht (OSBA St. No. 1, p. 30-31) and OCA's witness D. Smith (OCA St. No. 2, p. 19) argued that economic conditions could cause earlier retirements and that early retirements would raise energy prices.

188. Dr. Jones explained that Messrs. Knecht and Smith are incorrect because new, efficient CC units will tend to displace existing less efficient fossil units. This transition will lower rather than raise energy prices. PP&L St. 7-R, pp. 86-87.

189. PP&L also notes that Mr. Smith 's application of ENPRO assumes that all plants will remain in service throughout the projection period. This neither reflects PP&L's projected retirements nor the proposal of OCA witness La Capra that the Commission should use PECO's projection of revised retirement dates of the Keystone and Conemaugh stations.

190. Dr. Jones' use of PP&L's current projected retirement dates as used in PP&L's last rate case is appropriate and conservative. Retirements dates of other PJM units is similarly supported. However, if these older plants are retired earlier than expected, the record supports the conclusion that Dr. Jones' energy prices are overstated with a resulting understatement of PP&L's stranded costs.

191. Dr. Jones' forecasted energy and capacity prices provide a consistent and reasonable basis to determine PP&L's stranded costs of generation. The record in this proceeding demonstrates that the EGEAS model is the most realistic and reliable model for projecting energy prices. While numerous issues have been raised by various parties concerning the appropriate inputs to the model, the record demonstrates that inputs selected by Dr. Jones are consistent and properly reflect expectations in a competitive market.

V. REVENUE UNDER REGULATION

192. In developing its PUC-jurisdictional allocation ratios, PP&L began with the cost allocation study presented in PP&L Exhibit JMK 1. That study complies fully with the Commission's Final Order in PP&L's most recent base rate case at Docket No. R-00943271, and forms the basis for existing retail customer tariff rates. PP&L St. 3-R, p. 13. The applicable ratios shown in PP&L Exhibit JMK 1 were then adjusted for known and measurable changes to PP&L's existing wholesale bulk power contracts, its contract with UGI Utilities, Inc. - Electric Division (a partial requirements wholesale customer), and its full requirements contracts with wholesale municipal customers, including Citizens' Electric Company and Allegheny Electric Cooperative, Inc. The adjusted PUC-jurisdictional allocation ratios used to determine PP&L's overall level of stranded costs are shown in PP&L Exhibit JRS 1.

193. OCA witness LaCapra recommends that the Commission reject these changes and utilize instead, without modification, the PUC jurisdictional allocation factors approved by the

Commission in PP&L's most recent base rate proceeding. OCA St. 1, p. 9. Mr. LaCapra argues: (1) it is inconsistent with prior Commission practice; (2) the changes are "speculative"; and (3) the projected costs could be allocated to wholesale, not retail, customers. *Id.*[3/]

194. As explained by Mr. Krall, all Pennsylvania electric utilities, including PP&L, are required to demonstrate on an annual basis that they have adequate generating resources to meet the needs of their customers over a ten-year planning horizon. PP&L St. 10-R, p. 29. If PP&L failed to meet this requirement, it would have had to obtain the necessary resources either through a new generating facility or a power purchase agreement. *Id.*

195. In PP&L's case, the evidence plainly demonstrates that the Company will need additional capacity to meet future load growth. PP&L St. 10-R, pp. 30-31.

196. The capacity returning as a result of PP&L's expiring power supply contracts is needed to address its projected capacity deficiency and to maintain adequate reserves for reliability.

197. Even with this returning capacity, the evidence demonstrates that the Company's reserve levels will fall toward the low end of the Commission's acceptable range at the end of the 10-year planning period. PP&L St. 10-R, p. 32.

198. The parties' proposed adjustments to PP&L's jurisdictional allocators are inappropriate. The subject capacity is needed to adequately meet the needs of the Company's customers in the future.

199. Under traditional cost-of-service rate regulation, PP&L is entitled to an opportunity to earn a fair rate of return on its investment in facilities and assets dedicated to the service of the general public. Thus, in calculating the overall level of its stranded costs, PP&L appropriately included a return of and return on its unrecovered investments. The cost of equity is also relevant in determining the appropriate discount rate to be used in this proceeding.

200. The table below summarizes the Company's position regarding the rate of return that should be utilized to calculate stranded costs in this proceeding. The capital structure

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3/ Mr. La Capra's adjustment impacts each element of stranded costs. As shown on Table D, the net effect is to reduce stranded costs by $388.415 million. Environmentalist witness Schoengold argues that the proposed increasing retail allocation factor "has the effect of causing retail customers to subsidize PP&L's wholesale business." Environmentalists St. 1, p. 18. To address this alleged problem, Mr. Schoengold recommends that the Commission utilize a single, fixed allocation favor of 80% to determine the PUC-jurisdictional portion of each component of stranded costs. *Id.*

ratios and cost of long-term debt and preferred stock are the levels as of December 31, 1996, the end of the historic base period in this case.

	Balance Dec. 31, 1996	(1) Ratio	(2) Cost of Capital	(1) x (2) Weighted Cost of Capital	After Tax Rate
Long-term debt	$2,744,256	47.0%	7.89%	3.71%	2.17%
Preferred stock	454,911	7.8%	7.10%	0.55%	0.55%
Common equity	2,637,839	45.2%	11.50%*	5.20%	5.20%
	$5,837,006	100.0%		9.46%	7.92%

* Rate of return on common equity granted by the Commission in its Final Order at Docket No. R-00943271.

201. PP&L has reflected an 11.5% rate of return on common equity in its Restructuring Plan filing. PP&L St. 6, p. 2. The 11.5% rate of return is equal to the rate of return adopted by the Commission in its Final Order in PP&L's most recent base rate case at Docket No. R-00943271 (Order entered September 27, 1995). PP&L argues that an 11.5% rate of return on common equity is both reasonable and very conservative, as shown by the independent analysis performed by Mr. Paul R. Moul. PP&L's proposed 11.5% rate of return is 125 basis points *less* than the 12.75% rate of return recommended by Mr. Moul. PP&L St. 6, p. 2.

202. The cost of common equity does not lend itself to precise mathematical calculation. The computation necessarily requires the use of overly restrictive and, in certain respects, unrealistic assumptions. Thus, the use of more than one approach provides a range of results which adds reliability to Mr. Moul's analysis and better reflects the range of factors that motivate investors to commit capital to an enterprise. PP&L St. 6-R, p. 2.

203. As a check on the reasonableness of his primary results, Mr. Moul also analyzed the cost of equity for a Barometer Group. The Barometer Group consists of eight electric companies with risk characteristics similar to those of PP&L. PP&L St. 6, pp. 2-3.

204. Based on these results, Mr. Moul determined that the appropriate cost of common equity is at least 12.75%. PP&L St. 6, p. 3. On this basis, Mr. Moul concluded that the 11.5% rate of return on common equity reflected in PP&L's Restructuring Plan filing "is below that indicated by the market models." PP&L St. 6, p. 3. Moreover, this rate of return likely will underestimate the cost of equity over the next thirty years because it is based on a 1996 base period, during which interest rates were relatively low by historical standards. PP&L St. 6, p. 4. Mr. Moul subsequently updated his analysis to reflect

market data through May 1997. PP&L St. 6-R, p. 3. This analysis confirmed Mr. Moul's 12.75% cost of equity recommendation. PP&L St. 6-R, p. 3.

205. OTS witness Mr. Deardorff recommends an alternative cost of equity allowance of 10.25% in this proceeding.[4/] OTS St. SR-3, p. 2. Mr. Deardorff's recommendation is solely based on his application of the DCF model to PP&L and to a barometer group of thirteen electric companies. OTS St. 3, pp. 8-10.

206. Mr. Deardorff's proposed rate of return on common equity would produce earnings per share of only $1.77. PP&L St. 6-R, p. 6. This earnings level is lower than PP&L's earnings per share in any year since 1988 (with the exception of 1994 when several unusual occurrences artificially depressed earnings), and is significantly below the earnings per share of $2.00 to $2.10 forecasted for PP&L by Value Line. PP&L St. 6-R, p. 6.

207. Similarly, Mr. Deardorff's recommendation would fail to produce the necessary pre-tax interest coverage. Specifically, Mr. Deardorff's proposal will only result in 3.44 times pre-tax interest coverage. The Company's pre-tax interest coverage must be above the 3.5 times threshold for the A rating for an electric utility with an average business position. The Company's proposed 9.46% overall rate of return will meet this requirement because it will provide 3.65 times pre-tax interest coverage and thus will provide PP&L with reasonable credit quality to attract capital investment. PP&L St. 6-R, p. 8.

208. Mr. Deardorff's proposed 10.25% cost of equity allowance is inappropriate. The evidence demonstrates that Mr. Deardorff's recommendation significantly understates PP&L's cost of capital.

209. Mr. Gruber recommends that the Commission adopt a 6.6% return on common equity in calculating the WACC. In Mr. Gruber's view, the return on common equity should be reduced to reflect his belief that "the risk faced by the Company in recovering its stranded cost is near zero . . . ." OTS St. 1, p. 10. The OTS' proposed adjustment would result in a 7.25% pre-tax WACC and a 5.71% after-tax WACC, and would reduce PP&L's stranded cost claim to $3,671,499,000. OTS St. 1, p. 11.

210. Mr. Gruber's recommendation is completely at odds with Mr. Deardorff's proposed cost of equity allowance of 10.25%.

4/ Mr. Deardorff originally recommended a cost of equity of 10.50%. OTS St. 3, p. 6. Mr. Deardorff revised his initial recommendation on surrebuttal "to account for changes that have occurred in both analysts' growth forecasts and market data and to correct a computer programming error." OTS St. SR-3, p. 2.

211. Mr. Gruber's recommendation confuses the cost of common equity relevant to a calculation of PP&L's stranded costs on the one hand, with the carrying charge applicable to the CTC and the recovery of such stranded costs on the other. The Act defines stranded costs as costs that would have been recovered in a traditional regulatory environment *prior to the existence of a CTC*. 66 Pa.C.S. § 2804. Under traditional rate regulation, an accurate determination of a PP&L's revenue requirement requires that, at a minimum, the WACC reflect the Company's cost of common equity. Mr. Gruber's concerns regarding the carrying charge applicable to the CTC are irrelevant to a determination of PP&L's revenue requirement under traditional regulation.

212. Mr. Gruber is incorrect in arguing that PP&L faces near zero risk in recovering its stranded costs through the CTC. The record evidence shows that PP&L in fact faces significant risk in recovering its full stranded costs. This risk is attributable to: (1) the rate cap that will limit the Company's total charges to customers during the CTC collection period; (2) the many assumptions that necessarily were used to calculate the stranded costs upon which the CTC is based; (3) the lack of any true-up under the Act of actual costs against the estimated costs used to calculate stranded costs; (4) PP&L's estimated cost of capital at December 31, 1996, which may not reflect actual capital costs during the period 1999 to 2005; and (5) the Company's use of a lower rate of return on common equity than that required by investors. PP&L St. 6-R, p. 24. Each of these factors significantly increases the risk that PP&L will not fully recover its stranded costs.

213. The effect of Mr. Gruber's proposal is shown in PP&L Exhibit LAG 6. As noted in that exhibit, Mr. Gruber's risk-adjusted cost of equity results in an after-tax WACC of 5.71%, which is 72.1% of PP&L's proposed 7.92% after-tax WACC. Similarly, Mr. Gruber's risk-adjusted after-tax WACC effectively reduces PP&L's relevant book value by 26.3%, which is roughly the same percent reduction recommended by Mr. Gruber for the Company's proposed after-tax WACC. PP&L St. 19-R, p. 26. Mr. Gruber's proposal fails to accurately determine the full measure of PP&L's stranded costs.

214. OCA witness La Capra recommends that the Commission utilize a 10% rate of return on common equity in lieu of the PP&L's cost of equity of 11.5% in calculating the appropriate discount rate to be applied in this case. Mr. La Capra's recommendation is based on the 10% return on common equity approved by the Commission in PECO Energy Company's Qualified Rate Order proceeding at Docket No. R-00973877. OCA St. 1, p. 8. The effect of Mr. La Capra's proposal is to reduce the overall level of PP&L's stranded costs by approximately $135 million. PP&L St. 19-R, p. 30-31.

215. The fundamental problem with Mr. La Capra's recommendation lies in his utilization of the asset value method to calculate stranded costs. Using this method, Mr. La Capra claims to measure the market value of PP&L's generating assets to a *buyer*. However, Mr. La Capra fails to consider in his analysis a buyer's own cost of capital or capital

structure, both of which would significantly impact a buyer's offer to purchase PP&L's assets.

216. There is no support for Mr. La Capra's proposal to use a lower cost of common equity in calculating the overall level of PP&L's stranded costs. Indeed, Mr. La Capra conceded in cross-examination that there is no evidentiary support for his proposal since he had not conduced a cost of equity analysis to support his recommendation. Tr. 1778-1779.

217. The Company's proposed cost rates for long-term debt and preferred stock are 7.89% and 7.10%, respectively. PP&L St. 2, Exh. PRM 2, Schedule 1. These figures are based on PP&L's actual cost of debt and preferred stock at December 31, 1996, the end of the base year in this proceeding. These embedded cost rates are not in dispute.

218. PP&L included in its calculation of stranded costs the present value (as of January 1, 1999) of its generation-related net regulatory assets. The Company initially claimed $383,911,000 for such assets in its Restructuring Plan filing. PP&L Exh. JRS 1, Tab B, p. 1 of 117. PP&L subsequently revised its claim during the course of this proceeding to $354,326,000, a reduction of $29,585,000. PP&L Exh. JRS 1A, p. 1 of 121.

219. On December 13, 1996, the Company filed an Application with the Commission requesting permission to roll its Energy Cost Rate ("ECR") and State Tax Adjustment Surcharge ("STAS") into base rates in response to Section 2804(4) of the Act, 66 Pa.C.S. § 2804(4), which establishes price caps on the Company's rates. The Company's Application requested Commission permission to defer as a regulatory asset: (1) unrecovered energy costs as of December 31, 1996; and (2) a normalized level of estimated future on-going energy costs. On December 19, 1996, the Commission issued a Tentative Order at Docket Nos. P-00961131 and R-00963842 approving PP&L's Application ("Tentative Order"). PP&L St. 3, pp. 9-11.

220. The Tentative Order created two regulatory assets, both of which are reflected in the Company's Restructuring Plan filing. First, PP&L is claiming the actual undercollection of $17.2 million in energy costs as of December 31, 1996. Second, the Company seeks to include in its stranded cost calculation approximately $31.2 million of normalized, on-going future energy costs on an annual basis. PP&L St. 3, p. 11; PP&L St. 3-R, p. 19.

221. OCA witnesses La Capra and Catlin, and PPLICA witness Kollen oppose the Company's claim of $31.2 million on an annual basis for future on-going energy costs. OCA St. 1, pp. 6-8; OCA St. 3, pp. 5-7; PPLICA St. 3, pp. 17-21. These witnesses argue that PP&L has failed to support its claim.

222. PP&L Exhibit JMK 5 provides a calculation of the five-year average of actual energy costs incurred by the Company during the period 1992 through 1996. This five-year average amount demonstrates that PP&L's estimated future on-going energy costs will

exceed the level of energy costs rolled into base rates on January 1, 1997 as a result of the Tentative Order by approximately $31.2 million annually. PP&L St. 3-R, Exh. JMK 5.

223. Based on actual energy costs for the period January 1, 1997 through June 30, 1997, the Company already has under-recovered $22.5 million of the energy costs included in its base rates. PP&L St. 3-R, pp. 19-20. The Company expects to underrecover its energy costs by approximately $36 million in 1997 and $67 million in 1998. PP&L St. 3-R, p. 19, Exh. JMK 6.

224. The Company's claim for unrecovered energy costs deferred pursuant to PUC order is reasonable and should be approved.

225. The Company's claimed stranded costs reflect estimated additional severance and pension costs that PP&L expects to incur between 1997 and 2001 as a result of its projected decline in the number of employees as the Company prepares for a competitive market. PP&L St. 8, pp. 25-26; PP&L Exh. JRS 1, Tab F, p. 40 of 117. The Company calculated a five-year amortization of the costs incurred in each year, and included in its calculation of stranded costs $17.106 million, the net present value of the recovery of these deferred costs that are allocable to the generation function. PP&L St. 8, pp. 25-26.

226. The OCA argues that the claimed employee transition costs for 1997 and 1998 should be excluded. OCA St. 3, p. 10. This adjustment would reduce the balance of regulatory asset for employee transition costs by $10.793 million. The OCA also contends that incremental pension benefits should be excluded because such benefits will not result in added out-of-pocket costs due to the overfunded position of the pension plan. This adjustment would further reduce the regulatory asset by $8.003 million. As a result of these two adjustments, the OCA recommends that the Commission allow only $3.483 million of future on-going employee transition costs as a regulatory asset. OCA St. 3, p. 11.

227. PPLICA asserts that PP&L's claimed future on-going employee transition costs are speculative, and that the Company failed to reflect normal employee attrition in its calculations. PPLICA St. 3, pp. 22-23. Even if the Commission "conceptually" adopts this regulatory asset, PPLICA argues that such asset should be valued at $5.502 million, the net present value of future cash outlays. PPLICA St. 3, p. 23.

228. The evidence shows that the additional severance and incremental pension costs that the Company is claiming and expects to incur are the result of PP&L's transition to a competitive market. These costs are explicitly identified in the definition of "transition or stranded costs" in Section 2802 of the Act. The cost savings attributable to the anticipated employee reductions are reflected in A&G expenses related to the generation function which are included in operation and maintenance expenses. PP&L projected that A&G expenses will decline between 1997 and 2001 as the Company prepares for

competition, rather than increase at an annual inflation rate of 2.5 percent. PP&L St. 8-R, p. 50.

229. PP&L also fully reflected normal employee attrition for the period 1997 through 2001 in its calculations. The Company used a conservative estimate of employee attrition even though the actual historical rate of attrition has averaged approximately 2.5 percent. Indeed, PP&L expects the rate of "normal" attrition to be even lower than the historic rate because a large number of employees already have left PP&L as a result of its restructuring initiatives. Despite this anticipated downward trend, the Company elected to utilize a more conservative forecast in calculating employee transition costs, and assumed that as many as 5 percent of the projected 381 departing employees would leave as a result of "normal" attrition. PP&L St. 8-R, pp. 51-52.

230. The OCA's recommendation to exclude incremental pension benefit costs also is not supported by the record evidence. The OCA's argument rests on the fact that the Company's pension plan is currently "overfunded." These "excess" pension fund assets are the result of the accounting method utilized to track these assets and the strong performance of the stock market in recent years.

231. The value of future pension benefits earned by all participants during the current year is approximately $32 million per year for 1997. However, the stock market's performance has produced a substantial amortized, unrecognized net gain that reduces the amount included in expenses and used to project future costs to only $5.7 million for 1997. Any additional offset to reflect "excess" plan assets as a regulatory liability, including OCA's recommended disallowance would "double count" the unrecognized net gains unless the full $32 million of the annual value of benefits earned is used as the basis for charges to customers. PP&L St. 8-R, pp. 31-32.

232. Mr. Kollen recommends that the Commission recognize a regulatory liability of $253.832 million at December 31, 1998 associated with the Company's alleged "excess" pension fund assets. PPLICA St. 3, pp. 14-16. In Mr. Kollen's view, the purported overfunding may be "utilized by the Company either to offset future pension expense or to withdraw in some manner, albeit with certain limitations and penalties."

233. Mr. Kollen's proposed adjustment in inappropriate. As Mr. Schadt explained. PP&L St. 8-R, p. 33):

> Mr. Kollen's pension fund adjustment amounts to trying to pay two bills with one check. Mr. Kollen would not change the pension expense reflected in the filing, the amount of which is reduced substantially by actuarial calculations that take into account, on an ongoing basis, the total value of current plan assets and projected earnings on those assets. He then, having taken

> advantage of the projected long-term value of those assets to reduce pension costs already reflected in the filing, recommends that the same assets be used over again to reduce regulatory assets.

234. The evidence establishes that "the full amount of the plan's assets and obligations are already and appropriately being used to lower the amounts currently charged to ratepayers and to offset future pension expense, which lowers the Company's estimate of stranded costs." PP&L St. 8-R, p. 32.

235. In its Restructuring Plan filing, PP&L reflected $189 million for taxes recoverable in its calculation of stranded costs. The Company's claim was calculated using the regulatory method which reflects the recovery of these costs over a 30-year period. As explained by Mr. Schadt, that method permits a simple straightforward calculation of taxes recoverable:

> A comparison of future book depreciation with future tax depreciation identifies exactly the future period in which the taxes will become payable. This also is the period in which taxes recoverable should be collected from ratepayers, under traditional ratemaking. Note that this is true because the proper linkage exists between rate base, deferred taxes and taxes recoverable. As rate base is depreciated over time, deferred taxes become payable to the government and taxes recoverable become due from ratepayers. PP&L St. 8-R, p. 14.

236. The OCA and PPLICA recommend that the Commission adopt the asset value method to calculate PP&L's stranded costs. As all parties acknowledge, however, the asset value method cannot be used to calculate taxes recoverable. To address this problem, Mr. La Capra uses the regulatory method to calculate these costs. However, it is only appropriate to utilize the regulatory method to calculate stranded costs related to taxes recoverable if such method is used consistently with the regulatory model, i.e., the difference between book depreciation and tax depreciation "drives" taxes recoverable. PP&L St. 8-R, p. 16. As Mr. Schadt explained, "[i]f book depreciation is eliminated from the calculation of stranded costs, as it is in the asset value model, there is absolutely no theoretical justification for amortizing taxes recoverable on the basis of book depreciation, and alternative amortization logic must be developed . . . ." PP&L St. 8-R, p. 16.

237. Existing accounting rules will require PP&L to recognize that stranded generation costs will be recovered through the CTC over a seven-year period. Consequently, related unfunded deferred taxes also will reverse over the same seven-year period, which in turn requires the reversal of taxes recoverable over the same seven-year interval. Thus, when properly calculated under the asset value method, stranded costs for taxes recoverable equal the present value of the Company's $548 million of taxes recoverable discounted

over a seven-year period, or $419 million. PP&L St. 8-R, pp. 16-17. Mr. La Capra's hybrid approach fails to reach this result.

238. PP&L included Taxes Other Than Income in its calculation of stranded costs. The Company's claim includes two components: (1) capital stock taxes; and (2) Public Utility Realty Tax ("PURTA"). PP&L calculated the actual amount of capital stock and PURTA taxes in 1996 applicable to fossil and nuclear generation facilities. The Company then escalated the 1996 taxes at the rate of inflation (2.5 percent) over the life of each generating facility. PP&L St. 8-R, p. 35; PP&L Exh. JRS 1, pp. 4-5.

239. OTS, OCA and PPLICA each oppose the Company's claim. OTS and PPLICA argue that capital stock taxes should remain constant over the life of each generating facility, but that PURTA taxes should decline in relation to the decline over time in net plant balance resulting from depreciation. OTS St. 2, pp. 16-23; PPLICA St. 2, pp. 50-51. Adoption of OTS' adjustment would reduce PP&L's nuclear generation-related stranded costs by $280.7 million, and its fossil generation-related stranded costs by $66.1 million. OTS St. 2, pp. 22-23. OCA recalculated PP&L's stranded costs assuming that Taxes Other Than Income would remain constant over the life of the Company's nuclear and fossil generating facilities reducing PP&L's stranded costs by $182 million. OCA St. 1, p. 16.

240. Section 2810 of the Act states that the transition to retail competition shall be revenue neutral as to the Commonwealth. 66 Pa.C.S. §2810. To achieve revenue neutrality, PP&L's claim reflects two assumptions. First, PP&L assumed that, similar to the Company's costs, the cost of services provided by the Commonwealth would increase with inflation. Second, PP&L assumed that the various tax revenues collected by the Commonwealth would increase proportionally to fund the higher cost of goods and services.

241. PP&L's claim is fully consistent with the requirements of Section 2810 because it assures that the transition to competition will be revenue neutral with respect to the Commonwealth. The opposing parties' recommendation would freeze capital stock and PURTA tax revenues to the Commonwealth at 1996 levels. This recommendation is inconsistent with the revenue neutrality goal of the Act.

242. PP&L's calculation of stranded costs includes $315.867 million attributable to the costs of decommissioning its various fossil generating units. PP&L escalated each fossil plant's decommissioning costs at a 2.5 percent annual rate of inflation to the end of its book life. The Company assumed that it would incur decommissioning costs over a three-year period -- 40 percent in the year each plant is retired, 40 percent the following year, and 20 percent the next year. PP&L Exh. JRS 1, p. 8.

243. The OCA and PPLICA recommend that the Commission exclude the Company's claimed costs in their entirety. Generally, the parties offer four arguments. First, the OCA asserts that fossil decommissioning costs "simply do not fit the definition of stranded costs." OCA St. 1, p. 18. Second, PPLICA contends that the Company's claimed costs are speculative and unsupported. PPLICA St. 3, pp. 30-35. Third, PPLICA argues that recovery of such future costs consistently has been denied. Fourth, OCA and PPLICA contend that allowance of PP&L's claim would provide it with a competitive advantage over non-Pennsylvania utility fossil generation suppliers who must incur decommissioning costs without the prospect of recovering such expenses from customers through a CTC. OCA St. 1, p. 18; PPLICA St. 3-S, p. 31.

244. Section 2803 of the Act defines "transition or stranded costs" as including "retirement costs attributable to the utility's existing generating plants other than the costs defined in Paragraph (1)," which refers to the recovery of nuclear generating plant decommissioning costs. 66 Pa.C.S. § 2803. Thus, fossil decommissioning which are incurred to retire existing fossil generating facilities are defined by the Act as allowable "transition or stranded costs."

245. PPLICA argues that the Company's claimed fossil decommissioning costs are speculative and unsupported. Specifically, Mr. Kollen asserts that PP&L's claim derives from a fossil decommissioning study performed by TLG Services which is based on three erroneous and speculative assumptions: (1) PP&L's fossil generating facilities will be decommissioned while owned and controlled by the Company; (2) the facilities will be retired on the dates indicated in the study; and (3) the facility sites will be restored to "greenfield" conditions. PPLICA St. 3, pp. 31-32.

246. PP&L in fact has submitted substantial evidence in this proceeding which fully supports its estimated future fossil decommissioning costs. Indeed, past industry experience suggests that PP&L's claim may be understated, as decommissioning estimates generally have proven to be much lower than the actual costs incurred. PP&L St. 3-R, p. 34. The TLG study is very similar to other studies relied upon by the Commission to establish allowable levels of nuclear decommissioning expense. Tr. 1486. The nuclear decommissioning study performed by TLG and relied upon by the Commission in PP&L's last base rate proceeding contained the same types of assumptions that Mr. Kollen now attacks in the TLG fossil decommissioning study in this proceeding. Tr. 1486-1488.

247. PP&L's estimate of stranded generation-related capital and operating expenses was calculated utilizing the revenue requirements methodology contemplated by the Act. PP&L St. 3-R, pp. 31-32. Using this methodology, the Company included in its calculation the costs of decommissioning existing fossil generating facilities that would be recoverable under traditional rate regulation at the end of the lives of those facilities.

Thus, PP&L's claim reflects its projected fossil decommissioning costs at the point in time when they actually would be incurred. PP&L St. 3-R, p. 32.

248. The OCA's and PPLICA's competitive advantage argument is inconsistent with the Act and, in fact, would place PP&L at a competitive disadvantage. The owners/operators of non-Pennsylvania utility fossil generation facilities can provide for the cost of decommissioning over the lives of their facilities. Pennsylvania utilities, however, must defer the recovery of fossil decommissioning costs until the costs are actually incurred. Pennsylvania electric utilities are required to seek and obtain stranded cost recovery of those costs or be placed at a significant competitive disadvantage. PP&L St. 3-R, pp. 32-33.

249. While OTS does not oppose PP&L's proposed stranded cost recovery of fossil decommissioning costs, Mr. Gruber recommends that the Commission require the Company to place all amounts recovered in a separate, non-qualified trust fund that would be accessible only as fossil decommissioning costs are actually incurred. OTS St. 1, p. 15.

250. Mr. Gruber's recommendation is inappropriate and inconsistent with Section 2806(A) of the Act that provided that "the generation of electricity shall no longer be regulated as a public utility service or function . . ."

251. Under the Act, PP&L is required to bear all of the risk associated with the estimate of its fossil decommissioning costs. Specifically, the Act permits the stranded cost recovery of the net present value of PP&L's projected fossil decommissioning costs. Thus, PP&L must bear the risk that its estimate understates such costs.

252. In recognition of this substantial risk, PP&L should not be required to place the amounts collected in a separate trust fund. PP&L St. 3-R, pp. 34-35.

253. In calculating the annual revenue requirement for nuclear generation, the Company included the amount it is recovering in annual nuclear decommissioning expense through existing retail and wholesale rates, adjusted to the appropriate PUC-jurisdictional amount. PP&L St. 8, p. 11. Currently, PP&L is recovering approximately $9.5 million per year in jurisdictional rates for nuclear decommissioning costs. PP&L St. 3, p. 15. PP&L's stranded cost claim reflects the net present value of after-tax future annual nuclear decommissioning expense accruals over the remaining life of the Company's nuclear facilities.

254. PP&L also proposes, as its preferred alternative, to recover its nuclear decommissioning costs over the remaining life of its nuclear generating facilities. PP&L St. 3, p. 14. Such costs would be recovered as part of distribution charges on a per kWh basis. PP&L St. 3-R, p. 28.

255. The Company's proposal is reasonable because it will ensure that it fully recovers its nuclear decommissioning costs over the remaining life of its facilities, and that it retains its exemption from burdensome NRC financial assurance requirements.

256. Two concerns underlie PP&L's proposal for recovery of nuclear decommissioning costs. First, there is some question as to whether the transition to full competition will ensure the adequate recovery of nuclear decommissioning costs. Section 2808 of the Act, 66 Pa.C.S. § 2808, provides electric utilities "an opportunity" to recover stranded costs through the CTC, including nuclear decommissioning costs that may not be recoverable in a competitive generation market. Thus, PP&L will have to fund a substantial amount of its nuclear decommissioning costs using revenue from market rates. There is no assurance, however, that such market rates will be sufficient to satisfy PP&L's nuclear decommissioning funding obligations. PP&L St. 3, p. 12.

257. Second, there is a risk that the transition to full competition could subject PP&L to substantial financial qualification requirements under Nuclear Regulatory Commission ("NRC") regulations. Specifically, NRC regulations exempt "electric utilities" to provide additional financial assurance for nuclear decommissioning (e.g., insurance or surety bond) beyond establishment of an external sinking fund. "Electric utilities" are defined as "any entity that generates or distributes electricity and which recovers the cost of electricity, either directly or indirectly, through rates established by the entity itself or by a separate regulatory authority." 10 C.F.R. § 50.2

258. Under traditional cost-of-service rate regulation, PP&L satisfies the NRC's definition of "electric utility" because its rates are set by the Commission. PP&L currently is authorized to recover its estimated future nuclear decommissioning costs in rates over the remaining life of its nuclear generating facilities, and all recovered amounts are placed in an external trust fund. However, the Act requires that all generation-related costs, including those related to PP&L's nuclear generating facilities, be removed from traditional rate regulation. PP&L's proposal to recover its claimed costs through a distribution charge is designed to address both of these concerns. PP&L St. 3, pp. 13-14. PP&L's proposal will ensure adequate nuclear decommissioning funding and will provide for the recovery of such costs through rates established by the Commission. PP&L St. 3, pp. 14-15.

259. PPLICA and the Environmentalists oppose the Company's proposal. PPLICA contends that PP&L's proposal to recover nuclear decommissioning costs on a per kWh basis is inconsistent with its treatment of such costs in its last base rate case. PPLICA St. 1, pp. 55-56.

260. Mr. Baron is in error. The Company unbundled costs in this case using the same demand allocators utilized in its last base rate proceeding. Thus, PP&L's proposed unbundled

tariff rates reflect nuclear decommissioning costs allocated among customer classes on a demand basis. The Company proposes to recover these demand-allocated costs on a per kWh basis, which is the same method currently used to recover such costs through fully regulated rates. PP&L St. 3-R, pp. 28.

261. The Environmentalists oppose PP&L's proposal to extend the CTC, and recommend that the Commission consider "the benefits of an incentive framework for nuclear decommissioning costs, in which risks are shared between the Company and its customers." Environmentalists St. 2, p. 28.

262. PP&L's proposal is consistent with the Act, which clearly states that the PUC "shall" provide for recovery of nuclear decommissioning costs. 66 Pa.C.S. § 2808(c)(1). Moreover, adoption of this proposal would clearly jeopardize PP&L's NRC status as an "electric utility" and could result in a pre-funding requirement that would impose an additional burden on customers. See also PP&L St. 3-R, pp. 29-30.

263. PPLICA initially opposed the Company's proposal to recover nuclear decommissioning expenses as a distribution-related component of its delivery charges, claiming that PP&L would recover such expenses twice. PPLICA St. 3, p. 39. In rebuttal, PP&L explained that it would exclude nuclear decommissioning costs from those recovered through the CTC if the Commission adopts the Company's proposal. PP&L St. 3-R, p. 29. Based on this clarification, PPLICA agreed that PP&L's proposal would not result in the double recovery of nuclear decommissioning costs. PPLICA St. 3-S, p. 33.

264. The Energy Policy Act of 1992 ("Energy Act") establishes an assessment on utilities, including PP&L, with nuclear power operations to provide funds for the decontamination and decommissioning of the Department of Energy's ("DOE") uranium enrichment facilities. Under the Energy Act, this charge is assessed over a 15-year period, and is deemed a necessary and reasonable current cost of fuel that is fully recoverable in rates in the same manner as other fuel costs. PP&L St. 8, p. 24.

265. PP&L determined the amount of DOE assessment costs that would be recovered annually through existing rates, and included the present value of the PUC-jurisdictional portion of this amount in its calculation of stranded cost. PP&L St. 8, p. 24.

266. The OCA and PPLICA recommend that the Commission disallow the Company's claim in its entirety, noting that PP&L already reflected this assessment in its Restructuring Plan filing as a component of fuel expense. OCA St. 3, p. 7; PPLICA St. 3, pp. 24-25.

267. In response, the Company eliminated all DOE assessment amounts from the fuel expense component of its generation-related costs, which reduced PP&L's stranded costs by approximately $17 million. PP&L St. 8-R, pp. 56-57. This correction fully addresses the OCA's and PPLICA's concerns.

268. PP&L's stranded cost calculation includes a claimed regulatory asset for incremental maintenance costs incurred during refueling and inspection outages PP&L's Susquehanna Steam Electric Station ("SSES"). These costs are deferred and amortized from the end of the outage until the next scheduled refueling and inspection outage is completed. The Company determined the annual recovery that would occur through existing rates and included in its stranded cost calculation $7.996 million on a present value basis at December 31, 1998 for the PUC-jurisdictional portion of these costs. PP&L St. 8, p. 25.

269. OTS, OCA and PPLICA each oppose the Company's claim for deferred SSES refueling expenses, asserting that refueling expenses are typical, ongoing costs that properly should be normalized, not deferred and amortized for future recovery. OTS St. 2, p. 15.

270. The Company's claim is fully consistent with the manner in which PP&L historically has accounted for and recovered SSES refueling costs. PP&L did not claim costs associated with the first refueling outage of SSES Unit 1 in its 1983 SSES Unit 1 rate filing with the Commission (Docket No. R-822169). Instead, the Company requested and received permission to defer and amortize its incremental refueling costs over the period of time from the date of restart following the outage until the date of restart after the next outage. PP&L St. 8-R, p. 46.

271. PPLICA and OCA contend that PP&L's claimed costs are premised on a change in accounting caused by the Company's change to a 24-month refueling cycle for SSES Unit 1 in 1997 and for SSES Unit 2 in 1998. PPLICA St. 3, p. 36; OCA St. 3, p. 9. As a result of this change, PPLICA notes that SSES Units 1 and 2 will undergo refueling outages in alternate years, which will cause the Company to expense actual outage costs each year. PPLICA and OCA argue that, despite these changes, PP&L has failed to modify its accounting practices to eliminate deferrals and amortizations in 1997 and 1998, and instead "has assumed that it can defer the accounting recognition of those changes into the 'subsequent to 1999' period, although it had no accounting order from the Commission that authorized such a deferral." PPLICA St. 3, p. 37. PPLICA and OCA, therefore, recommend that the Commission disallow the Company's request.

272. PPLICA's and OCA's recommendation is in error. PP&L was authorized to accumulate and defer the first refueling outage costs for SSES Unit 1 over the subsequent fuel cycle. Thus, PP&L always has been one cycle behind in recovering refueling outage costs. The parties' recommendation would result in an improper matching of outage costs and revenues. PP&L St. 8-R, pp. 48-49.

273. In its Final Order at Docket No. R-00943271, the Commission authorized PP&L to recover the full PUC-jurisdictional portion of expenses attributable to the adoption of Statement of Financial Accounting Standards 106 ("SFAS 106"). SFAS 106 requires PP&L to record the liability associated with post-retirement benefits on an accrual basis

(i.e., at present value), rather than on a pay-as-you-go or cash basis. The Company's current rates recover the full SFAS 106 costs applicable to PUC-jurisdictional customers, including approximately $11 million in excess of PP&L's current cash payment obligation for post-retirement benefit claims to recover the transition obligation or accrued liability that existed as of January 1, 1993, the date PP&L adopted SFAS 106. The transition obligation is being amortized over 20 years. PP&L St. 8, p. 22; PP&L St. 8-R, pp. 41-42.

274. The Company determined the annual recovery of SFAS 106 costs that would occur under existing rates and included the present value of the PUC-jurisdictional portion of the generation-related amount in its calculation of stranded costs. PP&L St. 8, p. 22.

275. PPLICA generally accepts the Company's claim, but recommends that the Commission recognize a regulatory liability for the interest earned by trust funds established by PP&L to fund post-retirement benefits other than pensions. PPLICA St. 3, pp. 26-29. In PPLICA's view, this regulatory liability should be used to offset PP&L's claimed regulatory asset.

276. PPLICA's proposed adjustment is inappropriate because the interest identified by Mr. Kollen already is utilized to offset or reduce the projected cost of post-retirement benefits other than pensions. PP&L St. 8-R, p. 40. PPLICA's proposal, if adopted, would increase PP&L's estimated generation-related stranded costs. PP&L St. 8-R, pp. 42-43.

277. With the change in Federal tax laws that allowed PP&L to take advantage of investment tax credits ("ITCs"), the Company elected to defer recognition of these credits as income by recording a liability for accumulated deferred ITCs. The amortization of accumulated ITC's, along with the related income tax effect, reduces the cost-of-service (and thus customer rates) over the lives of the assets that produced the ITCs. As a result of the adoption of Statement of Financial Accounting Standard No. 109 ("SFAS 109"), PP&L recorded a deferred tax asset to reflect the income tax effect of the accumulated deferred ITCs, and a regulatory liability (i.e., an amount owed to customers) to reflect the ratemaking treatment of the tax effect. This regulatory liability is equal to the reduction in income tax expense that will need to be recovered from customers as the balance of accumulated deferred ITCs is amortized to reduce the cost-of-service over the remaining lives of the underlying assets. PP&L St. 8, pp. 28-29.

278. In its Restructuring Plan filing, PP&L utilized the present value of the ITC regulatory liability to reduce or offset the present value of regulatory assets in calculating the level of its stranded costs. The methodology used by the Company to reflect the effect of the ITC regulatory liability is not opposed by any party in this proceeding.

279. In calculating its stranded cost claim, PP&L utilized the same deactivation dates for its generating facilities that were approved by the Commission in the Company's most

recent base rate case at Docket No. R-00943271. Specifically, the Keystone and Conemaugh generating stations are scheduled to be deactivated in 2007 and 2010, respectively. These deactivation dates also are fully consistent with the depreciation schedules reflected in PP&L's retail customer rates as of January 1, 1997. PP&L St. 10-R, pp. 33-36.

280. The OCA and PPLICA recommend that the Commission extend the deactivation dates for both the Keystone and Conemaugh generating stations to match the dates utilized by PECO Energy Company ("PECO") for its share of these plants in its Restructuring Plan proceeding at Docket No. R-00973953. OCA St. 1, p. 16; PPLICA St. 3, pp. 31-32.

281. PP&L's proposed deactivation dates are consistent with the expected operating life for this type of generating unit. Specifically, the Keystone units began service in 1967 and 1968. Based on the deactivation date approved by the Commission in PP&L's last base rate case, i.e., 2007, these units have projected service lives of 40 and 39 years, respectively. Similarly, the Conemaugh generating units began operation in 1971 and 1972. Based on the deactivation date approved by the Commission in PP&L's last base rate case, i.e., 2010, these units have an expected operating life of 39 and 38 years. PP&L St. 10-R, pp. 35-36. As Mr. Krall explained, the Company's proposed deactivation dates properly reflect the design and operating limitations for these units. PP&L St. 10-R, p. 36.

282. The parties' reliance on PECO's proposed deactivation dates is misplaced. In fact, the various owners of Keystone and Conemaugh frequently have utilized different deactivation dates in establishing their respective rates. The Commission has reviewed and approved each of these dates.

283. Mr. Kollen is incorrect in asserting that PECO's deactivation dates should be utilized because PECO operates the Keystone and Conemaugh units. The record evidence demonstrates that these generating units are operated by GPU subject to oversight by the Keystone-Conemaugh Projects Office. PECO, like PP&L, is a joint owner, and no owner may unilaterally cause investments at these stations that would extend their lives. Such investment decisions require approval by 75% of all ownership shares. Because the Commission lacks jurisdiction over five of the owning companies whose ownership shares exceed 25%, the Commission is unable to require investments to extend the lives of these stations. PP&L St. 10-R, p. 37.

284. PP&L's proposed deactivation dates are appropriate. The proposed dates are identical to the dates approved by the Commission in the Company's last base rate case, and are fully consistent with the expected operating lives of the facilities.

285. The Company included in its calculation of stranded costs the present value of the generation-related portion the total annual recovery of rate case expenses that would

occur through existing rates. The Commission authorized PP&L to recover rate case expenses associated with its base rate proceeding at Docket No. R-0094371 over a four-year period. PP&L St. 8, p. 26.

286. Raising the same argument used in opposition to PP&L's claim for deferred SSES refueling expenses, the OTS and OCA recommend that the Commission disallow the Company's claim. Specifically, Messrs. Reed and Catlin argue that the Commission previously approved normalization of PP&L's rate case expenses, not deferral and amortization of such costs. OTS St. 2, pp. 13-16; OCA St. 3, p. 12. Disallowance of the unamortized expenses would reduce the nominal balance of the Company's regulatory assets by $184,000. OCA St. 3, p. 12.

287. PP&L properly included the balance of its unamortized rate case expenses as a regulatory asset in its Restructuring Plan filing. SFAS 71 allows a regulated entity to match incurred costs with their associated revenues for accounting purposes using regulatory assets. Under SFAS 71, the recorded regulatory assets are charged, concurrently with the recovery of such amounts in rates, to the same account that would have been charged if included in income when incurred. Based on the Commission's Final Order in PP&L's last base rate proceeding, the Company appropriately created a regulatory asset in September 1995 for the 1994 Rate Case Expenses to be amortized over a four-year period. Consistent with the Act, PP&L reflected the present value of the post-1998 recovery of the generation-related costs in its calculation of stranded costs. PP&L St. 8-R, pp. 39-40.

288. On rebuttal, the Company corrected an error in its original stranded cost calculation related to the Safe Harbor facility. Specifically, PP&L's initial calculation did not include the energy revenues and the operating and maintenance expenses associated with this facility. The revenues related to Safe Harbor's capacity inadvertently were included with the Holtwood Dam hydroelectric project's revenues for capacity. The effect of properly including the remaining revenues for energy from Safe Harbor and all of its operating and maintenance costs increases PP&L's stranded costs by $38 million. PP&L St. 8-R, pp. 55-56. These corrections are shown in PP&L Exhibit JRS 8.

289. PP&L's stranded claim included the generation-related portion of its Administrative and General ("A&G") expenses between generation and T&D using the same allocation factors approved by the PUC in PP&L's 1995 rate case. OCA witness La Capra recommends that the Commission exclude certain A&G expenses from the Company's going-forward generation-related costs. OCA St. 1, p. 16.

290. By excluding these costs from generation-related expenses and failing to reallocate them to the transmission and distribution function, Mr. La Capra effectively eliminates the claimed A&G expenses and precludes their recovery. Mr. La Capra's proposal is in error. The claimed A&G costs are necessary for PP&L to continue to provide safe and reliable

service to its customers. These costs will not disappear following the transition to competition. If these costs are not recovered as generation-related stranded costs, they must be reallocated and recovered through regulated transmission and distribution rates.

291. OCA proposed a productivity factor of 0.2% to reduce projected future operation and maintenance expenses and alleges that PP&L failed to reflect possible future productivity gains. OCA St. 1, pp. 24-25.

292. Contrary to OCA's assertions, PP&L did use a productivity factor in its calculations of stranded costs. Instead of increasing administrative and general costs, a component of operation and maintenance expenses, by 2.5% annually, the inflation rate used in other portions of PP&L's calculation, PP&L reduced administration and general costs by an average of 2% annually for each year after 1997 through 2001. PP&L's method of reflecting increased productivity reduces PP&L's stranded costs even more than OCA's method. PP&L St. 8-R, pp. 54-55; Ex. JRS 7. The additional adjustment proposed by OCA is unjustified because it would "double count" PP&L's projected reductions in operation and maintenance and administrative and general expenses of $513 million. PP&L St. 2, p. 16. A portion of these expense reductions undoubtedly will come from increased efficiency of employees. There is no basis for the OCA's adjustment.

293. The OCA asserts that PP&L has failed to recognize the value of the real estate on which its generation units are located as a factor mitigating its overall level of stranded costs. OCA St. 1, pp. 28-29. In OCA's view, the minimum value of such real estate is $66 million. OCA Exh. RLC-6. The OCA's analysis is flawed and its adjustment is significantly overstated, and it should be rejected.

294. The OCA recommends that the Commission adopt the asset value methodology to determine the Company's stranded costs. OCA St. 1, pp. 14-15. In its calculations, the OCA treats capital additions as expenses in the year in which they are incurred. Similarly, the OCA reflects the full associated tax deductions in the year in which the underlying capital expenditure is incurred.

295. The OCA's treatment of capital additions is in error. The proper treatment of capital expenditures is to record depreciation expense ratably over the life of the investment and to provide for a return on the undepreciated balance, *i.e.*, rate base. OCA's asset value method cannot handle this complexity so Mr. La Capra makes the simplifying assumption that the entire expense was incurred in the year it was made. From an expense standpoint this is acceptable, as long as the discount rate is the same as the return which would have been allowed if the investment were depreciated under normal ratemaking practice.

296. The problem with OCA's analysis lies in its treatment of taxes. OCA assumes that the tax deduction for the entire capital expenditure can be taken in the year it was made.

This, of course, is not true. The tax laws require that a deduction equal to the nominal value of the expenditure be spread over the life of the investment utilizing IRS tax depreciation guidelines. As a result of this error, OCA significantly understates the actual cost of capital additions and overstates net market revenue by overstating the tax reducing effect of the expenditure. This error caused the OCA to understate PP&L's stranded costs by $165.318 million.

VI. DETERMINATION OF PRESENT VALUE

297. PP&L used the regulatory method to calculate its stranded costs. Under this method, the Company compared the revenue stream it could have received under traditional cost-of-service regulation with the stream of revenue it could receive in a competitive market. PP&L discounted the difference between these two amounts to January 1, 1999 using a discount rate of 7.92%, which is PP&L's after-tax weighted average cost of capital ("WACC"). PP&L St. 8-R, p. 5; PP&L Exh. JRS 1, p. 1.

298. OSBA witness Knecht argues that PP&L's proposal to use a 7.92% after-tax WACC "would provide a higher [net present value] return to equity holders under deregulation plus CTC than under continued regulation." OSBA St. 1, p. 21. To address this alleged problem, Mr. Knecht asserts that the Commission should adopt PP&L's proposed 11.5% after-tax cost of equity as the appropriate discount rate. OSBA St. 1, p. 16. Under Mr. Knecht's proposal, PP&L would underrecover less than $100 million of its total stranded costs. OSBA St. 1, p. 24. Mr. Knecht purports to support his adjustment both algebraically and with an example. OSBA St. 1, pp. 18-21; OSBA Exh. RDK-2, Schedules 1-3.

299. Mr. Knecht's proposal to use the after-tax cost of equity ignores the fact that PP&L has both equity *and* debt investors. Indeed, Mr. Knecht conceded this point during cross-examination. Tr. 804. As explained by Mr. Guth. PP&L St. 19-R, p. 23):

> a utility's earnings on capital invested consist of both earnings on equity and earnings on debt. Using the after-tax WACC takes into account the balance of earnings between equity and debt.

Under Mr. Knecht's proposal, however, a component of PP&L's total returns, i.e., interest paid to debt-holders, will be discounted at *equity* rates. PP&L St. 19-R, p. 24. This mismatch is inappropriate. Mr. Knecht's proposal should be rejected.

300. The OCA asserts that PP&L improperly applied an *after-tax* discount rate the calculate the present value of *pre-tax* revenue requirements and market prices. OCA St. 1, p. 13. As a result, the OCA claims that the Company overstates its stranded costs by $880 million. *Id.*

301. OCA's argument is in error. Stranded costs are analogous to economic damages because they represent a decrease in value caused by some act or event, in this case, the transition from regulated to market-based rates. PP&L St. 19-R, p. 20. As such, taxable stranded costs properly should be measured utilizing pre-tax cash flows and after-tax discount rates. PP&L St. 19-R, p. 21.

302. Messrs. La Capra and Falkenberg reflect income taxes in calculating the value of PP&L's generating assets, but fail to adjust stranded costs upward to account for the taxability of CTC revenues. PP&L St. 19-R, p. 21. As Mr. Guth explained, Messrs. La Capra and Falkenberg. PP&L St. 19-R, pp. 21-22):

> computed what they assert is the market value of PP&L's generating assets after taking into account income taxes. That procedure is all right, so long as measured stranded costs are then adjusted upward to take into account the taxability of CTC revenues that are based on stranded costs. Thus there really are two alternatives where the present value amount of future cash flows is taxable income:
>
> 1. use pre-tax cash flows, and after-tax discount rates to compute the present value of taxable income; or
> 2. use after-tax cash flows, and after-tax discount rates to compute the present value of after-tax income, then gross up the result for tax coverage.

The OCA's proposal is incorrect because it fails to adopt either of these approaches.

VII. RECOVERY OF STRANDED COSTS

303. Under Section 2808(a) of the Act, 66 Pa.C.S. § 2808(a), electric distribution companies will recover their stranded costs through "Competitive Transition Charges ("CTCs"). These charges will be applied to every customer of electric distribution companies.

304. Three statutory provisions influence the rate design of PP&L's CTCs. First, the CTCs are constrained by the rate caps. Under Section 2804(4)(ii) of the Act, there may be no increase in the generation component of rates, which includes the CTCs, for nine years from the Act's effective date, or through December 31, 2005. That is, throughout this period, the sum of each CTC and PP&L's charge for Basic Utility Supply ("BUS") Service may not exceed the generation component of rates charged to customers as of January 1, 1997. Second, Section 2808 of the Act mandates that the CTCs be designed "in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the Commission in the electric utility's most recent base rate proceeding." Third, PP&L's CTCs are

designed in a manner to promote the overall purpose of the Act, which is to establish an active and viable retail market for electric generation.

305. In addition to these statutory considerations, PP&L has applied sound ratemaking principles in designing its CTCs. PP&L has sought to provide a more efficient marginal price signal to customers. PP&L St. 9, p. 20. Further, PP&L has simplified its delivery service rate design.

306. PP&L used a "bottom-up" approach to design its CTCs. PP&L St. 9, pp. 23-26. The starting point for this approach is presently-effective rates. The first step is to determine for each rate in each rate schedule, the portion of the rate that is related to delivery of electric energy. This was determined by application of allocation percentages based upon a test year ended December 30, 1995. These allocation percentages were accepted in the Commission's Order entered in PP&L's most recent base-rate case (Docket No. R-00943271, order entered on September 27, 1995, at 197).

307. PP&L's next step in determining the CTCs is to subtract from the generation portion of each rate the projected retail market price of electric energy. The remainder after this substraction is the portion of the rate that is available for use as the CTC under the rate cap.

308. PP&L has determined that, under the rate cap, the maximum CTC revenue that can be attained over the transition period through 2005 is only $4.0 billion. St. 10-R, p. 3. Thus, due to the rate caps, PP&L's projected CTC revenues will fall $500 million short of recovering all of PP&L's estimated $4.5 billion of stranded costs. Therefore, PP&L set its proposed CTCs at the maximum amounts available under the rate cap after allowing for the projected retail market price of electric energy and the portion of each rate that is for delivery services.

309. Although the rate cap does not change throughout the transition period, the projected retail market price of electric energy increases each year of the transition period. Therefore, for each rate, there is a different CTC for each year of the transition period through 2005. See, *e.g.*, Exhibit OGK 2, Tariff Electric-Pa. P.U.C. No. 201, pp. 20-21.

310. PP&L's rate design for its CTC meets each of the statutory and ratemaking principles identified above. First, it successfully meets the Act's rate cap requirements. There will be no increase in PP&L's rates for generation service at least through 2005. The applicable rate cap under the Act is the presently-effective generation portion of the total rate. By calculating the CTC as the residual remaining after subtracting the delivery portion of the rate and the projected retail market cost of electric generation during the transition period (which is the maximum charge for PP&L's BUS Service) means that PP&L's proposed CTCs arithmetically cannot exceed the rate cap.

311. The evidence shows that PP&L's proposals will not cause shifting of costs between rate classes or within rate classes. The generation portion and the delivery portion of PP&L's present rates were determined by application of allocation percentages from the cost of service study used to design PP&L's present rates. St. No. 3, pp. 6-7; Exhibit JMK 1.

312. PP&L's CTCs have been designed to achieve simplicity in the delivery service rate design. The CTCs have declining blocks that follow PP&L's presently-effective rate design. The delivery charge includes the presently-effective customer charge and flat usage charges per kWh. Therefore, when the CTC is eliminated at the end of the transition period, the remaining charges of PP&L under rate schedules for most customers will be a customer charge combined with a flat energy charge for usage. Customers will understand this pricing structure and be able to work with it to obtain electric energy at the most favorable terms and conditions (St. 9, p. 21).

313. Several intervenors suggest that, contrary to PP&L's proposal, the level of the CTC should be re-established periodically throughout the transition period based upon actual market prices. NEV St. No. 1, pp. 3-4, 7, 9; MAPSA St. 1, p. 2; Environmentalists St. 1, pp. 2, 8.

314. Recalculating CTCs periodically based upon ever changing market conditions would make effective competition extremely difficult. Without a known CTC, customers would not be able to compare the applicable rate cap for PP&L's BUS Service with proposals from alternative suppliers to determine whether using services of an alternative supplier would be more advantageous. PP&L St. 9-R, p. 11.

315. A CTC that is recalculated periodically could substantially defeat the benefits of competition for customers. If competition is effective and retail electric generation prices are lower than projected, PP&L's proposed CTCs would not provide for full recovery of its stranded costs. Thus, the result of a lower market price would be a higher CTC, not savings for customers. St. 9-R, pp. 18-19.

316. OCA, in its St. 4, pp. 9-14, and OSBA, in its St. 1, p. 12, recommend, based on an assumption that PP&L will be allowed to recover a much lower level of stranded costs than it has proposed, that recovery of stranded costs be spread over the transition period.

317. The OCA's and OSBA's proposal would delay recovery of the allowed level of stranded costs and would impose on PP&L an increased risk that it will be unable to recover all of its allowed stranded costs if market conditions change in the future. Moreover, the CTC should be set at the maximum level consistent with the rate cap until the allowed level of stranded costs is recovered because this approach will eliminate the distortions on the electric energy market prices caused by the CTCs at the earliest possible date. PP&L St. 9-R, pp. 22-25.

318. Various parties in this proceeding have proposed alternative methods for PP&L to recover its stranded costs. The proposals by other parties consist of "levelizing" or otherwise unnecessarily spreading recovery of stranded costs over time. These proposals are inappropriate. First, they are calculated on the unfounded assumption that a substantial portion of PP&L's stranded costs will be disallowed by the Commission. Second, levelizing recovery of stranded costs has the effect of shifting that recovery from the early years of the transition period to the later years. The result is a significantly adverse impact on PP&L's financial indicators in those early years, compounding the financial impact of any disallowance of stranded cost recovery.

319. AARP contends that costs should be reallocated so that a larger share of CTC revenues is derived from non-residential customers. AARP St. 1, pp. 28-29. In a similar vein, the Environmentalists contend that the Commission should take a fresh view of allocating stranded costs among the rate classes. Environmentalist St. 1, p. 26.

320. The AARP and Environmentalist proposals directly contravene the mandate of Section 2808(a) of the Act, which requires that the CTC be established in a manner that does not shift cost recovery either between classes of customers or within a customer class. The Act also specifies the manner in which this result is to be accomplished by requiring that stranded costs be allocated in the manner accepted by the Commission in each electric utility's most recent base-rate case. AARP and the Environmentalists ignore these statutory provisions.

321. The Act provides specific guidance concerning the reconciliation of CTC revenues and stranded costs. Section 2808(a) of the Act provides that annual CTC revenues shall be reconciled with the amortization of stranded costs authorized by the Commission for the same period.

322. PP&L proposes to implement this statutory mandate by following procedures, subject to one exception, similar to the annual Energy Cost Rate ("ECR") reconciliation procedures that had been in place in Pennsylvania for many years prior to the Act (St. 3, p. 17). PP&L proposes to track, on a system basis, its annual CTC revenues and compare those revenues with the annual amortization authorized by the Commission. PP&L would submit quarterly filings to the Commission reporting the results of the tracking process. However, in a departure from ECR practice, PP&L would not change its CTC annually to reflect overcollections or undercollections.

323. Because PP&L's rates will be at the rate caps throughout the transition period, PP&L would be precluded by the rate caps from recouping from customers any prior period undercollection. Accordingly, PP&L is proposing that the collection period be extended or contracted to permit reconciliation of overcollections or undercollections. That is, if CTC revenues exceed the authorized amortization, the CTC would be terminated at the appropriate time prior to December 31, 2005. Conversely, if CTC revenues were less

than the amount authorized by the Commission, the CTC period would be extended beyond December 31, 2005.

324. Section 2808(b) of the Act provides that the CTC may be included in bills to customers for a period not to exceed nine years from the effective date of the Act, or December 31, 2005. The Act further provides, however, that the Commission "for good cause shown" may order an alternative payment period. This alternative period may be longer or shorter than the nine-year period. PP&L has shown good cause why the period for application of the CTC should be extended if CTC revenues during the period ending December 31, 2005, fall short of the level of stranded costs that PP&L is authorized by the Commission in this proceeding to recover from customers. St. 3, pp. 18-19.

325. PP&L's proposal to extend the period for reconciliation of stranded costs also protects the interests of customers. First, if the Commission approves PP&L's proposal to extend the period for recovery of stranded costs beyond December 31, 2005, PP&L will voluntarily extend the generation-related rate cap to coincide with the extension of the period for application of the CTC. St. 3-R, p. 26. Second, the CTC will be known and predictable throughout the transition period facilitating comparisons by customers of PP&L's BUS Service with offerings by alternative electric energy suppliers. Third, PP&L has kept the CTC mechanism as simple as possible, and has proposed that the reconciliation process not reflect any calculations of interest on overcollections or undercollections of the annual CTC amortization.. PP&L St. 3-R, p. 25.

326. OCA has recommended that the CTC be reconciled by rate class. OCA St. 4, pp. 17-18.

327. There is no support for OCA's proposal in the Act. Section 2808(f) is silent on the subject. Of greater importance, however, are the facts that OCA's proposal would not solve the perceived problem that it is intended to address and that OCA's proposal would create additional problems. The problem that OCA apparently seeks to address is that stranded cost recovery will be usage dependent, and different rate classes will pay more or less than allocated amounts depending on future levels of usage. However, under OCA's proposed reconciliation by rate class, this "problem" will remain unresolved for customers within a rate class. Inevitably, customers using more energy in the transition period will pay more than they would under allocations based on historical usage. Similar problems arise from additions and losses of customers. These "problems" are unavoidable unless the CTC is to be an entirely fixed charge and based on historical levels of usage. No party has made such a proposal.

328. OCA's proposal also would have the potential to cause hardship. In rate schedules with few, large customers, hardships could be caused to remaining customers if one member of the rate class went out of business early in the transition period. Problems would be caused also by having the CTC terminate at different times for different rate schedules.

Under these circumstances, some customers may be able to switch their service to a rate schedule without a CTC, thereby harming other customers or the Company.

329. A proper net present value determination must recognize also that PP&L's stranded costs will be recovered over seven years ending December 31, 2005. For the reasons that stranded costs are discounted to net present value, PP&L's recovery of stranded costs should be inflated to net present value.

330. Based on the Commission's Order in *PECO*, p. 108, the applicable rate to inflate PP&L's stranded costs to reflect the fact that recovery will take place over a seven-year period is PP&L's long term debt cost rate. *See also* PP&L St. 19-R, pp. 28-29. This rate, which is provided at PP&L Exhibit JRS 1, Tab A, Attachment 1, is 7.89%.

331. Regardless of the cost rate, however, a substantial portion of PP&L's assets, including stranded assets are financed with securities on which PP&L pays dividends that are subject to income taxes. For this reason, the portions of the amount to be inflated must be "grossed up" for income taxes. Exhibit JRS 1, Tab A, Attachment 1, provides PP&L's capital structure and cost rates. Exhibit JRS 1, Tab A, p. 4, provides its composite income tax rate of 41.4935%. Using these data, that have not been controversial in this proceeding, produces the appropriate rate to be applied to amounts to be recovered through the CTC over 7 years. Thus, the appropriate overall, pretax rate that should be used to inflate PP&L's CTC revenues, that will be received over a seven-year period, is 10.86%.

332. PP&L provides interruptible service under three rates schedules (IS-1, IS-P and IS-T). PP&L proposes to continue service under these rate schedules following transition to a competitive retail market for electric generation. Service, however, would be limited to premises presently receiving interruptible service and to customers who choose to purchase PP&L's BUS Service (See, *e.g.*, Exhibit OGK 2, Tariff Electric — Pa. P.U.C. No. 201, p. 30C).

333. The CTC for the interruptible rate schedules is calculated in the same manner as for all other rate schedules, *i.e.*, the remainder after the projected retail price of electric generation and the delivery component of the rate are subtracted from the fully-bundled rate. As a result, the CTCs applicable to the interruptible rate schedules are extremely small. For example, in 1999, the tailblock CTC under Rate Schedule IS-T is 0.257¢ per kWh, and this amount is reduced every year through 2005 when the tailblock CTC is a negative 0.006¢ per kWh.

334. These low CTC's result because the interruptible rates are deeply discounted. These discounts are generation-related.

335. Another benefit to PP&L's system of providing interruptible service is that PP&L can interrupt sales to interruptible customers when the cost to PP&L of generation service is exceptionally high. PP&L St. 11-R, pp. 3-4.

336. The benefits of providing interruptible service are available to any alternative supplier of electric energy. Interruptible service enables an alternative supplier to sell energy, during its non-peak periods, without the need to construct or purchase generating capacity that would be necessary to meet the additional load. Moreover, alternative suppliers that purchase electric energy to resell to their retail customers can interrupt sales to interruptible customers to avoid costs whenever the price for electric energy is high. However, if an interruptible customer of PP&L purchases electric energy from competing suppliers, the interruptible nature of the service will benefit the competing supplier and possibly its customers, not PP&L and not PP&L's other delivery service customers.

337. Certain customers propose to continue to utilize interruptible rate schedules of PP&L while shopping for competing generation suppliers. This proposal is illogical. Under these circumstances, the interruptible customers would continue to receive from PP&L the benefit of a deeply discounted rate for interruptible delivery service while providing no reciprocal benefits to PP&L or its customers.

338. To date, PP&L has never interrupted service under the interruptible rate schedules due to load peaks on transmission or distribution facilities. To the contrary, all interruptions requested by PP&L have been the result of generation emergencies on the PJM interconnection, for emergency tests of interruptible service customers or for economic reasons. St. 11-R, p. 8. There is no basis for discounting any such service, and therefore, no reason for offering such a service.

339. The interruptible customers also object to the provisions of PP&L's proposed tariff, Exhibit OGK 2, p. 30E, which give PP&L more discretion in interrupting service for economic load control.

340. PP&L's proposed economic load control provision is appropriate to protect PP&L's other customers. Interruptible customers and all other customers using PP&L's residual BUS Service will receive bills for service that are based upon an annualized, average cost of such service, subject to the rate cap. Therefore, if interruptible customers use electric energy when prices are high, the cost that such customers cause PP&L to incur are shared with other customers if the price does not exceed the rate cap. PP&L's present tariff rule, which limits interruptions to 200 hours per year or 2.3 percent of the time (200 ÷ (24 x 365)) is not sufficient to protect the interest of other customers of PP&L receiving BUS Service.

341. Interruptible customers' concerns are misplaced because, during interruptions for economic load control, interruptible customers are not required to terminate use of

electric energy. To the contrary, they are only required to make an economic choice. If an interruptible customer uses electricity during interruptions for economic load control, its only predicament is that it must play the charges under the interruptible rate schedule plus PP&L's estimated cost of replacement capacity and energy (Exhibit OGK 2, p. 30F).

VIII. RATE DESIGN

342. PP&L has proposed an innovative rate design for its CTC. PP&L's proposed CTC will be calculated for customers individually, that is, "customized," based upon their 1996 usage of electric energy. PP&L's customized rate design ("CRD") shifts one half of each customer's total CTCs from usage-based charges to fixed monthly CTC customer charges. PP&L St. 9, p. 5.

343. The effect of the CRD, in comparison with a more traditional usage-based (cents-per-kWh) charge are several. First, if each customer were to use during any year of the transition period ending December 31, 2005, the same amount of electric energy as it used during 1996, the customer would pay the same total amount of CTCs under both the CRD and the traditional, usage-based rate design. If, however, a customer were to use more electric energy per year during the transition period than in 1996, the customer would pay less under the CRD than under the traditional rate design. Conversely, if a customer were to use less electric energy annually during the transition period than in 1996, the customer would pay more under the CRD than under the traditional rate design.

344. PP&L's proposed CRD promotes a principal objective of the Act, which is to stimulate growth in the Pennsylvania economy. The CRD would produce rate reductions for incremental usage over 1996 levels which will likely be the case for most customers. For example, GS-1 customers will see a 16% reduction in their marginal rate; GS-3 will see a 5% reduction; LP-4 customers will experience a 6% reduction; LP-5 customers will experience a 8.5% reduction; GH-1 customers will experience an 11% reduction; and GH-2 customers will experience a 13.5% reduction on incremental usage. PP&L St. 9, p. 33.

345. The CRD will be calculated individually for each customer. First, each customer's usage during 1996 will be priced at rates established in this proceeding using a CTC calculated under traditional, usage based rates. This amount will then be divided by 12 to determine a monthly amount. One half of the monthly amount will be added to the customer charge. The remainder will be priced based on 1996 energy usage so that the annual cost of electric service will be unchanged from the annual cost for 1996. PP&L St. 10, pp. 11-12; PP&L St. 9, p. 33; PP&L Exhibit DAK 1.

346. The CRD, in addition to providing beneficial rate reductions for incremental usage, has other advantages. The CRD represents a movement toward marginal cost pricing, enabling customers to make better informed energy usage decisions. The CRD also

reduces the distortive effects of stranded cost collection on energy use while maintaining some continuity with present rates by moving only half of transition charges into fixed customer charges. PP&L St. 9, p. 6.

347. PP&L has also demonstrated flexibility in determining which customers should be subject to the CRD. PP&L has presented three proposals for applicability of the CRD:

(1) PP&L's first and primary proposal (Tr. 760) is that the CRD be optional for residential customers but mandatory for all other customers. This proposal has the maximum potential for stimulating the economy of PP&L's service territory, while allowing flexibility for PP&L's residential customers, many of whom are not sophisticated in regulatory rate matters. PP&L's primary concern, which has led it to propose that the CRD be mandatory for all non-residential customers, is that an optional CRD would lead to a substantial shortfall of stranded cost recovery. Revenue erosion will be inevitable, if reconciliation is based upon energy sales, instead of CTC revenues.

(2) Due to this concern, PP&L's first alternative position is that, particularly if reconciliation is to be based upon energy sales instead of CTC revenues, the CRD be eliminated. PP&L St. 10-R, p. 16.

(3) If, however, appropriate revenue protections were instituted, that is, reconciliation were based upon actual CTC revenues and not energy sales, PP&L would be willing to make the CRD optional for all customers. Under this alternative, customers would have the option to elect the CRD or the traditional rate design. Such elections would remain in effect for a minimum of 12 months. After 12 months, the customer's choice of the CRD or traditional rate design could be revised, but any change would have to remain in effect for a minimum of 12 months. PP&L emphasizes, however, that, under this proposal, CTC reconciliation must be based upon a comparison of actual CTC revenue for a period with the amortization allowed by the Commission for the same period. Any over or undercollection of CTC revenue would be resolved by shortening or lengthening of the CTC collection period, with a concomitant extension of the generation rate cap. (Tr. 734).

348. OCA has opposed the CRD as causing a shift of costs from customers with increasing usage to customers with decreasing usage and as being a less efficient rate design. OCA's basis for this contention is that the marginal cost of transmission and distribution costs can exceed embedded costs. OCA St. 4, pp. 15-16.

349. Although PP&L's proposed CRD would recover less stranded cost from customers that increase energy usage, there is no prohibition against such a rate design in the Act.

350. OCA's contention, that the CRD shifts costs, is circular. It is correct only if one assumes that OCA's preferred traditional rate design is the only CTC rate design permitted under

the Act; OCA's comparison of the CRD with the traditional rate design demonstrates the point that the traditional rate design and the CRD are different; it does not demonstrate that the traditional rate design is correct.

351. OCA's concern is substantially ameliorated by PP&L's third option under which all customers may choose the CTC rate design applicable to them. OCA's proposal would not promote the economy of PP&L's service territory.

352. OCA's second concern related to relative levels of incremental transmission costs and embedded costs is irrelevant. PP&L explained that it has no plans for substantial investments to expand its transmission system (Tr. 825-26).

353. PP&L presently offers a series of incentive rates that are designed, by various means, to promote economic growth in PP&L's service territory or to improve PP&L's load factor or both. These rates include riders and rate schedules and billing options. Riders include the economic development incentive ("EDI") rider, the industrial development incentive ("IDI") rider and the Competitive Rate Rider ("CRR"). Billing options available under certain rate schedules include demand free days and time of day ("TOD") billing options. Rate schedules include the Price Response Service, Rate Schedules PR-1 for firm service and PR-2 for interruptible service and Residential Thermal Storage ("RTS") service.

354. Many of the incentive rates in PP&L's presently-effective tariff are scheduled to terminate in the relatively near future. PP&L St. 11, pp. 8-13. Despite the fact that these incentive rates, as a result of prior proceedings before the Commission, are scheduled presently to terminate in the near future, PP&L has proposed to continue these rate schedules, under which certain customers receive substantial benefits. PP&L St. 11, p. 14. PP&L's proposal to continue these incentive rates is based upon its interpretation of the rate cap in Section 2804(4) of the Act. The practical effect of phasing out these incentive rates would be that affected customers would pay more for service than they would pay if the incentive rates were continued.

355. PP&L proposes to limit incentive rates to customers presently served under them and to limit the availability of incentive rates to customers who use PP&L's BUS Service for energy supplies because all of these incentive rates were designed to increase utilization of PP&L's generation resources or improve the efficiency in use of PP&L's generation resources or both. St. 11-R, pp. 3-4, 8-9. The benefits of the incentive rates are not related to PP&L's delivery service. Instead, they are designed to benefit the provider of generation services. Any incentives or discounted rates should be offered by the energy suppliers, not the delivery service supplier. Discounting delivery service rates to improve utilization of generation facilities is a relic of vertically integrated utility service and bundled rates that makes no sense once a competitive retail electric energy market is established. PP&L proposes that the incentive rates be retained only for PP&L BUS Service customers. In this way, to the extent that customers improve the load profile and

utilization of BUS Service, thereby creating benefits that can be shared with other BUS customers of PP&L, PP&L will continue to make incentive rates available. Otherwise, incentive rates are not proper and should not be included in delivery service rates.

356. The Act provides that any customer returning to BUS Service is to be treated as a new customer. Because new customers are not eligible for incentive rates, returning customers similarly are not eligible for these incentive rates under Section 2807(4) of the Act.

357. PP&L proposes the following changes to existing tariff rules:

> Rule 4 is changed to indicate that the Company may upon request supply services over and above those which the Company would normally provide, if the customer agrees to pay the Company a fair and non-discriminatory price for those related services.
>
> Rule 9E was changed to indicate that the Budget Billing interest rate is changed from the number 1% per month to 1-12 of the average of 1-year Treasury Bills for the months of September, October, and November of the previous year.

358. Tariff Rule 9E was changed to conform to the amendments to the Commission's regulation at 52 Pa. Code § 56.57.

> Rule 6A has been amended to exclude fuel supply disruption from qualifying for backup power supply.
>
> E(5) has been added to the tariff to indicate that a customer-specific, fixed, per month CTC developed by the Company, which will equal 100 percent of the customer's estimated CTC revenue, will be applied if the customer elects to install on-site generation on or after January 1, 1999.

359. Provision E(5) was based on Section 2808(a) of the Act, which permits recovery through a non-bypassable CTC of stranded costs from customers with new on-site generation facilities. Under Section 2808(a), the CTC for such customer should be fixed and recover the customer's fully allocated share of stranded costs.

360. None of the tariff changes have been controversial.

361. Section 2804(9) of the Act requires that:

> The commission shall ensure that universal service and energy conservation policies, activities and services are appropriately funded and available in each electric distribution territory. Policies, activities and services under this paragraph shall be funded in each electric distribution territory by nonbypassable, competitively neutral cost-recovery mechanisms that fully recover the costs of universal service and energy conservation services.

362. PP&L has allocated its universal service costs on a customer basis. PP&L St. 3R, p. 36. This is the manner in which such costs have been allocated in cost of service studies accepted previously by the Commission in PP&L's most recent base-rate proceeding at Docket No. R-00943271.

363. OCA, in its St. 6-S, pp. 15-23 and OTS, in its St. 2, pp. 2-8, have raised issues concerning the manner in which rates are to be designed to recover PP&L's costs of providing universal service activities and services. OTS and OCA have recommended the universal service charges be allocated on an energy, or per kWh, basis.

364. The Act expresses strong support for continuity of rates based on each electric distribution company's most recent base-rate proceeding. *See* 66 Pa.C.S. § 2808(a).

365. PP&L's stranded costs exceed maximum CTC revenues under the rate cap during the transition period. Therefore, it is not possible to reallocate universal service costs without violating the rate cap applicable to customers that would receive a greater portion of universal service costs than would be allocated to them under PP&L's proposal.

366. OCA also provides an alternative allocator using non-production revenue as the basis for allocating universal service charges. OCA St. 6-R, pp. 20-22.

367. The OCA's alternative proposal suffers from the same deficiencies as its original proposal to allocate universal service costs based upon energy or KWh usage.

368. Under FERC Order No. 888, PP&L has proposed, subject to approval of the Commission and FERC, that its facilities operating at voltage is of 69 kV and above are transmission facilities and that facilities operating at less than 69 kV are local distribution facilities. No party produced evidence contesting PP&L's analysis.

369. PP&L's proposed unbundling of delivery charges is summarized at pp. 5-7 of PP&L St. 9-R. PP&L is proposing to unbundle its delivery charges into two principal categories, transmission and distribution. It is appropriate for the delivery charge to be divided in this manner so that retail customers can perceive correct price signals resulting from

taking power at different transmission voltages under alternative supply arrangements. Further, the unbundling of delivery charges into distribution and transmission charges is required under Section 2804(3) of the Act.

370. Transmission service, however, must be further unbundled. Retail access customers of PP&L will be required to utilize transmission services from PJM under the PJM Open Access Transmission Tariff. Customers will pay unbundled charges for transmission service and related ancillary services as specified in the PJM Open Access Transmission Tariff. The services will be identified and charges therefor established by FERC. St. 12-R, pp. 8-9.

371. OCA and OTS have contended that charges for universal service should be unbundled from distribution service charges as a separate line item on bills to customers. OCA St. 6, p. 45; OTS St. 3, p. 7.

372. The OTS and OCA proposal would cause customer confusion. Charges for universal service are "non-bypassable." Section 2804(9). Unbundling services on a customer's bill is appropriate only if the customer has some choice with regard to the unbundled expense. Customers cannot decline to pay charges for universal service; customers cannot obtain universal services from any other provider, at least through the end of the transition period. Consequently, there is no point to having charges for universal service unbundled into a separate billing line item. This is particularly true given the small amount of the per customer size of the universal service charge. It is far more appropriate to bring the universal service charges to customers' attention by means of a billing message rather than as an unbundled line item on each customer's bill. PP&L St. 10-R, p. 6.

IX. PHASE-IN ISSUES

373. The Act mandates the following phase-in schedule for retail access:

> [T]he following schedule for phased implementation of retail access shall be adhered to unless a determination is made by the commission under subsection (c) [which allows for an additional six month transition period under certain circumstances]:
>
> (1) As of January 1, 1999, a maximum of 33% of the peak load of each customer class shall have the opportunity for direct access.
>
> (2) As of January 1, 2000, a maximum of 66% of the peak load of each customer class shall have the opportunity for direct access.

(3) As of January 1, 2001, all customers of electric distribution companies in this Commonwealth shall have the opportunity for direct access.

66 Pa.C.S. § 2806(b). The Act gives the Commission specific instructions: "The time line for the transition to and phase-in of direct access to competitive electric generation shall be in accordance with section 2806." 66 Pa.C.S. § 2804(11).

374. PP&L's proposed phase-in schedule tracks that mandated by the Act. As described in the testimony of Mr. Henry W. Baumann, PP&L Sts. 14 and 14-R, PP&L proposes an initial sign-up period for each phase-in period during which all customers interested in participating in competition can notify the Company. If any rate classes are over-subscribed, PP&L will conduct a random selection among customers seeking to participate. PP&L St. 14-R, p. 4.

375. Enron, OSBA and PPLICA witnesses believe that this methodology should not apply to the selection commercial and industrial customers, based on the possibility that non-participating customers may suffer a competitive disadvantage over participating customers. *See* Enron St. 5.0, pp. 19-20; OSBA St. 1, pp. 51-52;. PPLICA St. 1, pp. 58-59.

376. PPLICA witness Stephen Baron asserts that the most appropriate methodology for selecting industrial customers is on a first-come, first-served basis, with the customer designating a desired level of load for participation. PPLICA St. 1, pp. 58-59. If there is an over-subscription of load, Mr. Baron proposes a pro-rata reduction to each subscriber's nominated load. To alleviate any remaining competitive disadvantages, Mr. Baron proposes that PP&L begin selection for the second phase and implement such a selection process by permitting retail access for up to 66% of peak load beginning January 2, 1999. PPLICA St. 1, p. 59.

377. Enron witness Mr. Bowen advocates a similar approach. Under Enron's proposal, Enron would be willing to accept the "first through the meter" approach, where Enron would supply the first portion of the customer's electricity received in a given hour and the EDC would supply the remainder. Enron would also be willing to "follow the customer's load" and provide a fixed percentage of its customers' load throughout the day. Enron St. 5.0, p. 20.

378. OSBA witness Robert Knecht suggests a variation on PPLICA's and Enron's approach to apply to commercial customers. He suggests that minimum levels of customer participation be set for the GS rate classes for each of two phase-in years. Under Mr. Knecht's proposal, if a rate class is over-subscribed and the random drawing produces too few customers, those few customers selected should be limited in the amount of their load that is subject to competition. OSBA St. 1, p. 53.

379. The phase-in schedule established under the Act is mandatory. The Act requires the Commission to establish regulations specifying that, within each customer class, the customers that are eligible for direct access during the phase-in period shall be determined by the Commission on a first-come, first-serve basis "unless otherwise determined by the commission . . . to prevent competitive disadvantages among similarly situated customers within a customer class." 66 Pa.C.S. § 2806(4). Neither Enron, OSBA nor PPLICA has made a showing of specific competitive disadvantage sufficient to justify a departure from the statutory presumption that the phase-in period will occur in the three stages established in Section 2806 on a first-come, first-served basis. PP&L St. 14, p. 5.

380. Customers who are participating in the PP&L's pilot program can enroll in and will be selected for retail access as described above, with one exception. Customers who are participating in PP&L's pilot program, but which are not selected for the first or second phase of retail access can elect to be "grandfathered" into retail access. However, customers in the Primary and Transmission/Subtransmission groups who have load limits in the pilot program will be limited to that level of load when "grandfathered" into retail access. PP&L St. 14, pp. 4-5. No party has opposed these procedures. They are reasonable and should be approved.

X. CODE OF CONDUCT

381. The Commission is in the process of developing regulations concerning Customer Supplier Interaction at Docket No. M-00960890.F0011 and has opened a rulemaking to receive comments on the recommendations contained in the Final Report of the Competitive Safeguards Working Group ("CSWG").

382. PP&L proposes that the Code of Conduct set forth in the testimony of Robert M. Geneczko, PP&L St. 13-R, Exh. RMG-4, should govern the relationship between its EDC and EGS until regulations of general applicability are adopted.

383. The FERC required utilities in Order No. 889 to adopt standards of conduct designed to functionally separate transmission and generation functions and to prevent transmission providers from giving themselves an undue preference over their customers though the exchange of "insider" information between the company's system operators and employees of the public utility, or any affiliate, engaged in wholesale marketing functions. *See* 18 C.F.R. § 37.4. PP&L plans to extend its Order No. 889 Code of Conduct to its retail transmission operations. PP&L St. 13, p. 5.

384. PP&L's proposed Code of Conduct will govern the relationship between PP&L's Generation Supply Group and its the Electric Delivery Group.

385. PP&L's proposed Code of Conduct is set forth in PP&L Exhs. RMG 2 and RMG 4; it is discussed in PP&L St. 13-R. PP&L's proposed Code of Conduct tracks the principles adopted by the Competitive Safeguards Working Group. Specifically, the Retail Access Code of Conduct provides for:

* Open, Non-Discriminatory Access to and Pricing of Regulated Monopoly Services. PP&L Exh. RMG 2, pp. 4-5; PP&L Exh. RMG 4, pp. 1-2.

* Prohibitions on Conditioning (Tying) of Access to Monopoly Services on Purchase from Generation Supply. PP&L Exh. RMG 2, pp. 4-5; PP&L Exh. RMG 4, p. 2.

* Non-Discriminatory Dissemination of Disclosed Market and Competitively Sensitive Information. PP&L Exh. RMG 2, pp. 3-5.

* Confidentiality of Customer and Supplier Information. PP&L Exh. RMG 2, p. 4; PP&L Exh. RMG 4, p. 1.

* Segregation of Personnel and Information by Group. PP&L Exh. RMG 2, p. 1; PP&L Exh. RMG 4, p. 1.

* Restriction of Information Transfer Via Personnel Assignment. PP&L Exh. RMG 2, pp. 2-3; PP&L Exh. RMG 4, p. 1.

* Separate Cost Allocation, Books, and Records. PP&L Exh. RMG 2, p.5; PP&L Exh. RMG 3, p. 2.

* Enforcement of Employee Education in the Codes of Conduct. PP&L Exh. RMG 2, pp. 5-6; PP&L Exh. RMG 3, p. 2.

* Compliance Reporting, Auditing and Dispute Resolution. PP&L Exh. RMG 2, p. 6; PP&L Exh. RMG 3, p. 2.

386. Enron witness Mr. Dirmeier asserts that PP&L's proposed Code of Conduct would lead to customer confusion because it does not go far enough to prevent PP&L's non-regulated operations from using the name of the EDC in a manner in which customers could reasonably imply that the electric generation supply is being provided by PP&L as the EDC rather than PP&L as the electric generation supplier. Enron St. 6.0 , p. 31-33; *see also* Enron St. 6.1, pp. 1-2.

387. Mr. Dirmeier is incorrect. There will be no customer confusion under PP&L's proposal by the use of the name "PP&L Energy Plus" because as described by Mr. Geneczko,

PP&L will clearly and explicitly distinguish delivery service and generation supply service as separate operations. Tr. 553.

388. The evidence shows that *prohibiting* PP&L's Generation Supply Group from using the PP&L name will lead to customer confusion and may deceive customers. Tr. 459 (8/18/97). Enron witness Mr. Dirmeier acknowledged that it would it be wrong to mislead customers as to who is providing their power. Tr. 687. As recognized by Mr. Dirmeier, a name benefits consumers by providing information and assurance. Tr. 439 (8/18/97). Mandating the use of a different name would deprive consumers of the added assurance of quality and price derived from putting the parent's reputation at stake.

389. The name PP&L and the good reputation associated with the name are shareholder assets, and, as such, have never been included in the rate base. The name and reputation of a utility therefore are not assets to which ratepayers have a claim.

390. Enron witness Mr. Dirmeier asserts that if there is value in PP&L's name, then the name should not be conferred without compensation. Enron St. 6.0, pp. 28-29, Enron St. 6.1, pp. 10-11.

391. The payment of a royalty is inappropriate for several reasons. First the utility's name is not a ratepayer asset. The imposition of a royalty would constitute a requirement that a regulated company dedicate its intangible assets, for which ratepayers have never paid and do not own, to the ratepaying public. Second, a percentage royalty, which is one type of royalty that has been proposed in other jurisdictions, does not bear any relationship to costs or benefits from the association of the affiliate with the utility and would be difficult if not impossible to value.

392. PP&L's proposed Code of Conduct provides that the Electric Delivery Group will not favor the Generation Supply group in any marketing of energy supply products. In addition, PP&L witness Mr. Geneczko agreed during the hearing that PP&L's Generation Supply Group will have access to bill inserts on the same terms and conditions as other electric generation suppliers. Tr. 586.

393. As clarified by Mr. Geneczko at the hearing, PP&L's Electric Delivery group may engage in joint marketing of energy supply products with PP&L's Generation Supply group, but will only do so as long as comparable opportunities are available to other suppliers and the purpose of the joint effort is economic development. The Electric Delivery group still has an interest and community responsibility to facilitate economic development, but is indifferent, however, as to which alternate suppliers provide the energy part of the package. It will inform alternative suppliers of any such arrangements on a "rather immediate" basis, which may include posting such arrangements on OASIS. Tr. 583

394. Several intervenors suggested that PP&L should be required to offer any surplus power to Alternate Suppliers.

395. Such a requirement would be an intrusion into the competitive process that the Act has determined "will no longer be regulated..." 66 Pa. C.S. § 2802(14). Moreover, such a requirement would be beyond the Commission's jurisdiction. The sale of surplus power to Alternate Suppliers is a wholesale transaction that falls squarely within the FERC's exclusive jurisdiction under the Federal Power Act ("FPA"). Section 201 of the FPA gives the FERC plenary, exclusive and non-delegable jurisdiction over such sales. 16 U.S.C. § 824(b)(1).

396. Enron witness Mr. Dirmeier suggests the need for an internet bulletin board to document *all* information shared between the Electric Delivery Group and the Generation Supply Group.

397. This recommendation is far too broad and is not supported by any provision in the Act. As explained by Mr. Geneczko, Company personnel necessarily will meet from time to time to discuss matters of a corporate nature, such as personnel, or matters relating to joint work outside of the Electric Delivery group's service territory. Much of the information discussed in these meetings is confidential in nature, the sharing of which is not necessary to achieve a competitive retail electric generation market.

398. Enron has proposed that in the time before direct access begins to be phased in, PP&L should not be permitted to enter into "market priced" contracts unless PP&L first offers to competitive suppliers the opportunity to bid to provide service to the customer and that customers who entered into such contracts subsequent to the date on which the Act was passed to cancel such contract. Mr. Dirmeier admits that he has no information that would lead him to believe that PP&L is engaging in the behavior he would prohibit.

399. As discussed by Mr. Kalt in his rebuttal testimony, Enron's request that the Commission "open up" pre-existing market-based contract is a transparent attempt to gain Commission intervention in competitive market to favor PP&L's competitors. PP&L St. 1-R, pp. 51-52. It is unreasonable and should not be adopted.

400. PP&L supports the Commission's effort to adopt uniform, state-wide standards of conduct. Until those standards are adopted, however. PP&L's proposed Code of Conduct should govern the relationship between its Electric Delivery Group and Generation Supply Group.

401. Several intervenors have argued in this proceeding that customer metering and billing services should be unbundled from other EDC customer services in order to create an additional opportunity to provide value-added services to consumers. *See* Enron St. 4.0, p. 3.

402. The Commission concluded in the PECO Order that Section 2807 of the Act, which sets forth the duties of electric distribution companies, does not assume that any additional unbundling is required and that "EDC's continue to have the duty to provide all distribution services, including metering and billing, in compliance with existing Commission requirements." PECO Order at 138-39. The record established in this proceeding mandates the same conclusion.

403. Several intervenors have argued in this proceeding that customer metering and billing services should be unbundled from other EDC customer services in order to create an additional opportunity to provide value-added services to consumers. *See* Enron St. 4.0, p. 3. The Commission has addressed these issues through various working groups, rulemakings and Orders. Although section 2804(3) of the Act provides that "the Commission may require the unbundling of other services" in addition to basic unbundling of transmission, distribution, and generation services, the Commission concluded in the PECO Order that Section 2807 of the Act, which sets forth the duties of electric distribution companies, does not assume that any additional unbundling is required and that "EDC's continue to have the duty to provide all distribution services, including metering and billing, in compliance with existing Commission requirements." PECO Order at 138-39.

404. As indicated the Commission's rulemaking at Docket No. L-00970120, the Commission has decided that it is unnecessary to unbundle metering as a competitive service at this time. In that rulemaking, the Commission outlined the standards and procedures to ensure that customers have real options for competitive metering while retaining all physical work related to metering as a regulated EDC function.

405. The Commission decided in the PECO Order that all customers may, in conjunction with their EGS, request use of a "qualified meter" that has been approved by the Commission based on the recommendations of a working committee composed of interested parties. The Commission will ensure that the list of qualified meters includes all meters necessary to support market services such as two-way communication, remote readings, time-of-use capability, and net metering.

406. PP&L witness Anthony M. Osmanski indicated PP&L's support for open system architecture for all metering services hardware and software. PP&L St. 21-R, p. 3. PP&L advocates the use of the standards currently being developed by the IEEE SCC-31 Standards Coordinating Committee. *Id.* PP&L believes that the installation of the actual metering hardware should remain part of the regulated distribution services. The energy information exchange would be provided as a "Standardized and Open Architecture" data stream to a customer interface. This interface gateway should be the marketable product open to competition, providing a receptacle for data and a gateway to communication and information services. The market may be driven to provide this information service with no initial cost to the customer. PP&L St. 21-R, p. 12.

407. Enron witness Raymond W. Bowen, Jr. suggests that payments received from customers by PP&L should be applied to services provided by PP&L and services provided by the supplier on a pro rata basis. Enron St. 5.0, pp. 16-1.

408. As Mr. Bowen acknowledged at the hearing, however, if payments are provided to the supplier on a pro rata basis, the amount of the EDC's non-recovery will increase. Tr. 1339-40 (8/22/97). Despite this fact, Mr. Bowen asserts that an increase in the amount of the EDC's non-recovery would not increase the EDC's cost of providing service. *Id.*

409. The Commission has already considered and rejected the pro rata payment approach advocated by Enron. *See* Final Order Re: Guidelines for Maintaining Customer Services at the Same Level of Quality Pursuant to 66 Pa.C.S. § 2807(D), and Assuring Conformance with 52 Pa. Code Chapter 56 Pursuant to 66 Pa.C.S. § 2809(E) and (F) (entered July 11, 1997). Instead, the Commission decided that the "priority" method of applying partial payments is preferable to the "prorata" method, particularly in terms of administering the process and complying with applicable Chapter 56 provisions at 52 Pa. Code §§ 56.23 and 56.24. Order at 32-33.

410. Enron witness Richard D. Tabors urges the Commission to require PP&L to make its PJM-allocated intertie benefits available to either its former retail customers who choose an alternative generation supplier or to that customer's supplier. Enron St. 8.0, p. 3.

411. It is well-established that the rates, terms and conditions of wholesales sales of power by public utilities fall squarely within the FERC's exclusive jurisdiction under the Federal Power Act ("FPA"). Section 201 of the FPA gives the FERC plenary, exclusive and non-delegable jurisdiction over such sales. 16 U.S.C. § 824(b)(1). The relief sought by Enron is beyond the scope of the PUC's jurisdiction, power and authority.

412. The Commission issued a Proposed Rulemaking Order Establishing the Standards for Changing A Customer's Electric Supplier at Docket No. L-00970121 in April 1997, which provides that a change of a customer's supplier may be initiated once the EDC has received direct oral confirmation from the customer or written evidence of the customer's consent. Under the proposed rules, "written evidence of the customer's consent" is limited to a document signed by the customer, the sole purpose of which is to initiate a change of electric suppliers.

413. Enron witness Mr. Bowen believes that the "written evidence" requirement should not require "direct" written communications from the customer through a letter of authorization or an agency agreement, nor should it require that the customer execute the document submitted to the EDC. Rather, Enron believes that "written evidence of the customer's request" should include any document which evidences to the EDC that customer consent was received by the supplier.

414. PP&L disagrees with this approach and continues to believe that incidences of slamming will be minimized if the customer is directly involved in the process. Tr. 1236. PP&L's proposal accomplishes the same goal as the Commission's proposed regulations—to ensure that a customer consents to the switching of its generation supplier. Under PP&L's proposal, an alternative supplier may provide written notification to PP&L of a customer's decision to purchase electricity from that alternative supplier. The Company will then send the supplier's written notification to the customer and request that the customer inform the Company if any of the information is incorrect or inaccurate. If the customer does not respond, the Company will assume the supplier's notification information is correct. PP&L St. 14, p.6.

XI. Customer Education

415. As explained by PP&L's witness, Dawn G. Lennon, the key principles of PP&L's CCEP are:

* PP&L will provide clear, balanced and practical explanations of what customer choice is, how it works, what the risks and trade offs are, and how to select an electricity supplier.

* PP&L will be recognized as a consistent, reliable and trustworthy source of information on customer choice.

* PP&L will separate customer choice education efforts from sales and marketing initiatives.

* PP&L will produce customer choice educational materials which are easy to read and understand and which meet high standards of objectivity.

* PP&L will pursue partnerships with the Commission and with educational, service, and consumer organizations in the development, implementation, dissemination, and evaluation of educational materials and programs on customer choice.

* PP&L will continue its customer choice education efforts to address new needs and changes, ensure understanding, and provide ongoing support for customers.

PP&L St. 17, pp. 4-5. PP&L's CCEP includes reliance on community based organizations ("CBOs") and other shareholder groups to assist PP&L in its education efforts.

416. PP&L's Customer Choice Handbook is the centerpiece of its CCEP. It will include an overview of restructuring of the electric utility industry, an explanation of customer

choice and how it works, consumer protection tips, worksheets for determining the customer's choice of suppliers and answers to important questions about the retail access market place.

417. In addition to the Handbook, PP&L will offer interactive telephone technology and presentations by customer choice educators. PP&L will sponsor a Customer Choice Education Advisory Committee composed of leaders from consumer, education and community organizations to oversee the development of customer choice educational workshops for target groups. The group will develop the details of the consumer education plan, commission the development of materials, design the methods of dissemination, analyze evaluation research on the program and ensure that PP&L's consumer education program provides balanced and unbiased knowledge to customers.

418. PP&L's CCEP is designed to be implemented on a local level by PP&L and various community based organizations. Nevertheless, PP&L will support and actively participate in a statewide effort if the Commission ultimately determines that such an effort is appropriate. As Ms. Lennon emphasized, however, a statewide effort alone cannot effectively educate customers. PP&L St. 9-R, p. 48.

419. PP&L disagrees with Enron witness Mr. Bowen's recommendation that the Commission or an independent third party under the Commission's supervision prepare and distribute educational information on a centralized basis. Enron St. 5, p. 28-29. While a Commission-led customer education program can be part of a successful education campaign, it cannot substitute for local customer education programs, which are best developed and implemented on a service territory by service territory basis.

420. PP&L has an obligation under the Act to provide balanced unbiased information from which customers can make an informed decision to exercise choice. Specifically, Section 2807(d)(2) of the Act requires each EDC to provide adequate and accurate customer information to enable customers to make informed choices. Section 2807(d)(3) of the Act further directs the Commission and each electric distribution company at to implement a consumer education program informing customers of the changes in the electric utility industry prior to the implementation of any restructuring plan.

421. The Commission recently initiated a proceeding regarding the Creation and Implementation of a Statewide Consumer Education Program for Electric Restructuring in the Commonwealth of Pennsylvania, Docket No. M-00981036 (entered Jan. 16, 1998). As the Commission recognized, "[p]articipation in a statewide media campaign or the use of CBOs on a local level does not eliminate the requirement that the EDCs actively participate in the comprehensive consumer education program at the local level." Order at 7.

422. The most useful tools to educate are reference materials (print, audio and website) that customers can access and revisit. While the use of mass media can be an effective tool to create customer awareness, it must be followed by information such as brochures, pamphlets, direct mail and other forms of communication to reinforce the "soundbite" messages of a media campaign. The best way to educate is to mobilize and equip people in the community using community-based organizations. Tr. 2009 (8/29/97).

423. PP&L provided the OCA with a five year preliminary budget for its CCEP. PP&L St. 17-R, Exh. DGL-2. This budget will allow PP&L to meet the stated objectives of its CCEP.

424. PP&L 's CCEP is based on extensive customer research. PP&L St. 17-R, p. 5-6. Based upon input from a variety of stakeholders, including the results of an independent customer research project, PP&L is revising its Customer Choice Handbook to provide education to consumers as the phase-in of full retail competition begins. Tr. 1974.

425. Evaluation of PP&L's overall education efforts will be ongoing throughout the transition to retail competition. PP&L St. 17, p. 7. PP&L's research will continue to focus on what customers know and understand about choice, the best vehicles for obtaining this information, the most credible sources of information, the usage profile and related demographics. Customers already surveyed will continue to be surveyed and compared to new customers. PP&L will share this information with the Commission.

426. Separation of PP&L's CCEP and its communications and marketing efforts is one of the key principles of PP&L's proposal. PP&L will not use its CCEP to market competitive business products. PP&L St. 15-R, p. 22. Its education efforts will not favor one supplier of energy or capacity over another. PP&L St. 17-R, p. 22-23. Customer choice education initiatives will be managed by the Company's Services department and customer information will be managed by Corporate Communications department. PP&L's marketing activities will seek to promote products and services through either its Delivery Services & Economic Development department or through its Generation Supply Group.

427. Enron witness Mr. Bowen suggests that PP&L's name should not appear on customer education communications. Enron St. 5, p. 31.

428. This proposal should be rejected. As stated by Ms. Lennon: "To develop and disseminate consumer education materials and not to put the Company name on them would be deceptive. Consumers are entitled to know where any materials come from so they can ascertain for themselves whether or not to accept the messages in them." PP&L St. 17-R, p. 23.

XII. Universal Service

429. PP&L has been among the industry leaders in implementing programs to address customer and community needs, especially those of low-income customers. In 1996, the Company's annual funding level for universal service programs and energy conservation programs was over $7 million. The Company has reviewed its existing programs and concluded that it must continue its leadership role in this area. As outlined in the testimony, of Timothy R. Dahl, PP&L plans to increase its annual funding for universal service programs and energy conservation programs from a current level of $7 million to approximately $14.3 million by the year 2002. PP&L St. 16, p. 4.

430. Section 2802(10) of the Act provides that "the commonwealth must at a minimum, continue the protections, policies and services that now assist customers who are low-income to afford electric service." Section 2802(17) specifies that the public purpose of the programs is to be "promoted by continuing universal service and energy conservation policies, protection and services and full recovery of such costs is to be permitted through a non-bypassable rate mechanism."

431. PP&L operates five programs that provide energy assistance to low-income customers. PP&L St. 16, pp. 8-13. These programs and their current level of funding are as follows:

Customer Assistance and Referral Evaluation Service ("CARES")	$260,000
Operation HELP	$795,000
Winter Relief Assistance Program (WRAP)	$3,023,300
Keep Warm Plan	$1,000,000
On Track Payment Program Pilot	$2,000,000
Total	$7,078,300

432. The Company is proposing to move OnTrack from its pilot phase to a full-time program. The level of enrollment would be increased from 1,040 customers to about 10,000 customers by the year 2001. This "ramping up" of OnTrack anticipates an increase of 3,000 new participants annually. The expanded OnTrack program will target customers who have annual household income at or below 150 percent of poverty; are payment troubled; and have an overdue electric bill.

433. There are approximately 58,000 customers who may be eligible for OnTrack based on the above characteristics. PP&L St. 16, p. 19. As a result, PP&L plans to concentrate the program on low-income customers who have a demonstrated inability to pay and may be subject to service termination.

434. PP&L plans to increase its expenditures by over $7 million dollars above current funding levels. The annual level of funding for OnTrack will be expanded from $2 million to $9 million over a three-year period beginning January 1, 1999. Because PP&L will continue to solicit donations from its customers and employees, donations to Operation HELP are expected to increase annually. PP&L proposes to maintain the current level of annual funding for CARES, WRAP, and the Keep Warm Plan. PP&L St. 16, pp. 17-18.

435. In general, intervenor witnesses propose an unreasonable and unwarranted increase in funding levels for universal service and energy conservation programs, in some cases to over three times current levels, and expansion of the programs' eligibility criteria. *See, e.g.*, testimony of OCA witness Ms. Nancy Brockway; CEO witnesses Mr. Michael Karp, Mr. Craig Kuennen, and Mr. Geoffrey Crandall; and AARP witness Mr. Mark Cooper. These proposals are not supported by the Act or the evidentiary record in this case.

436. The primary intent of the universal service provisions of the Act is to ensure that current protections for low-income consumers are maintained in a competitive generation market. 66 Pa.C.S. § 2802(10). The funding levels proposed by CEO, OCA and AARP simply were not envisioned by the Act. The intent of the Act is to restructure the electric utility industry to reflect competitive forces in the marketplace, not to implement a broad expansion of customer assistance programs.

437. As a basis for establishing the level of need for universal service and energy conservation programs, CEO's Mr. Kuennen presents information derived from the U. S. Census about poverty rates and the number of low-income households in PP&L's service area.

438. The 1990 U. S. Census data for the Company's service area show that approximately 177,000 PP&L customers are at or below 150 percent of the federal poverty guidelines. This guideline is the proposed eligibility standards for programs such as OnTrack and WRAP. However, most of these customers (approximately 70 percent) pay their electric bills and are not in arrears with PP&L. PP&L St. 16-R, p. 7. It would be counterintuitive for the Company to encourage customers who have been paying the full amount of their electric bills to join OnTrack and begin paying only a portion of their bills.

439. 48% of the capital expenditures necessary to operate PP&L's facilities for the period 1997 through 2001 will be incurred to ensure environmental compliance. Projected capital costs after 2001 include individual environmental compliance projects that likely will be required at each facility. PP&L St. 10-R, pp. 37-38. As Mr. Krall explained. PP&L St. 10-R, p. 38):

> A significant portion of these costs are to comply with provisions of the CAAA [Clean Air Act Amendments]. These costs include Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems for NOx reductions beyond those already achieved with the installation of Reasonably Available Control

Technology in order to comply with the likely requirements of Title I of the CCAAA [sic]. Other costs include scrubbers to remove air toxics and fine particulates to comply with Title III of CAAA. For the years 2003, 2004, and 2005, 54% of the $429 million of capital identified, or $230 million, will be for compliance with the CAAA, alone.

440. Mr. Schoengold offers no evidence to support his claim that existing plants enjoy a competitive advantage under the current environmental regulatory scheme. In fact, with the adoption of the Clean Air Act, environmental regulations have imposed increasing compliance burdens on existing plants. These compliance obligations have increased significantly with the passage of the Clean Air Act Amendments. Contrary to Mr. Schoengold's assertions, Mr. Krall explained that the current regulatory scheme is leading to the retirement of older plants in keeping with one of the basic "assumptions" identified by Mr. Schoengold as underlying the Clean Air Act. PP&L St. 10-R, pp. 39-40.

441. OCA witness Ms. Brockway recommends that PP&L's annual funding for OnTrack and weatherization (WRAP, Keep Warm Plan) should be $11.7 million and $4.7 million, respectively. OCA St. 6, pp. 23, 34. Ms. Brockway's proposal represents an increase in the funding levels suggested by PP&L of 30 percent (OnTrack) and 17.5 percent (WRAP and Keep Warm Plan). AARP witness Mr. Cooper has stated that deep discounts should be made available to all low-income households. AARP St. 1, pp. 25-26. The cost of extending OnTrack credits to all of PP&L's low-income customers would be prohibitive. The average OnTrack credit is $50 per month, or $600 annually. PP&L St. 16-R, p. 9. The cost of extending the credits, as Mr. Cooper suggests, would exceed $106 million annually (177,000 x $600).

442. CEO witness Mr. Kuennen recommends that PP&L target 40 percent of low-income households (specifically, 71,000 customers) for participation in OnTrack. CEO St. 1, p. 22. OCA witness Ms. Brockway suggests that PP&L should serve 18,500 customers in OnTrack. OCA St. 6, p. 30.

443. These proposals present three significant problems: 1) it would be impractical to effectively identify, interview, and enroll tens of thousands of customers; 2) the costs would be prohibitive; and 3) good-paying customers would be encouraged not to pay under the CEO's proposal.

444. Mr. Kuennan and Ms. Brockway also advocate increased funding levels for the baseload program under WRAP. As acknowledged by Ms. Brockway, each utility should tailor its energy conservation programs to address the conditions in its own service area. Tr. 2042.

445. Given that PP&L has the highest electric heat saturation rate of the eight major Pennsylvania electric utilities, PP&L Cr. Exam. Exh. 12, PP&L has properly chosen to focus its weatherization activities on electric heat customers.

446. CEO witness Mr. Kuennan and OCA witness Ms. Brockway suggest that PP&L's current level of write-offs and credit and collection expenses associated with non-OnTrack low-income customers could be "transferred" to fund an expanded OnTrack Program rather than booking write-offs and credit and collection expenses associated with these amounts, in essence reducing its billings to these customers. CEO St. 1, p, 26; OCA St. 6, p. 26. Ms. Brockway acknowledges that this approach would not improve PP&L's bottom line, yet she asserts that even if no associated benefits of lowered collection costs or improved dollar payment amounts were realized by PP&L, the customer would benefit from this transfer from a delinquent debt posture to one of a reasonable opportunity to make complete payments.

447. Ms. Brockway's proposal is inappropriate because it is based on the key false assumption that low-income customers do not pay any portion of their bills. PP&L's experience shows that low-income customers, even those that are payment-troubled, do often pay some amount toward their bills. For example, PP&L evaluated approximately 1,000 very low-income customers (at or below 110% of the federal poverty guidelines) and determined that even those customers pay PP&L six or seven times per year. Tr. 1948.

448. PP&L supports the OCA's recommendation to allow OnTrack customers to choose Alternative Suppliers subject to three important conditions. First, OnTrack participants who select an Alternative Supplier would be required to receive a single bill from PP&L. Second, as a condition of serving OnTrack customers, Alternative Suppliers would agree to discount the energy portion of the supply bill by a percentage equal to the overall percentage reduction established pursuant to the OnTrack program. Third, the Alternative Suppliers would agree to absorb the supply portion of the revenue shortfall that is written off monthly for OnTrack customers.

449. A key objective of OnTrack is to encourage and develop good payment habits among customers. PP&L proposes to offer one bill to OnTrack customers who choose an Alternative Supplier. A combined bill would streamline administrative procedures for the OnTrack agencies and reduce confusion for customers.

450. PP&L's average monthly electric bill for low-income, payment-troubled customers is about $88, and the average monthly electric bill for OnTrack customers is $47. In other words, the Company provides a monthly bill reduction of $41, or 53 percent. This revenue shortfall is written off monthly. PP&L St. 16-R, p. 22. PP&L recommends that Alternative Suppliers provide a pro rata reduction in energy supply charges to those OnTrack customers who choose an Alternative Supplier. Without such a pro rata

reduction, the evidence shows that the amount of the monthly bill reduction could reduce the transmission and distribution portion of the customer's bill to less than zero.

451. PP&L also believes that Alternative Suppliers should share in the costs of the revenue shortfall associated with OnTrack customers. Generation accounts for approximately 25 percent of the bill, and using the above example of the $41 revenue shortfall for the average OnTrack customer, an Alternative Supplier would be responsible for $10.25 of the write-off. The remaining $30.75 would be assigned to PP&L. Because the revenue shortfall includes some generation charges, it is fair for Alternative Suppliers to assume responsibility for the portion of their the revenue shortfall. PP&L's proposal would treat both PP&L and the Alternative Supplier on the same basis while satisfying the Act's objective of providing choice to all customers in Pennsylvania. It is reasonable and should be approved.

452. Environmentalists witness Bruce E. Biewald proposes that the Commission require all retail electricity suppliers selling in Pennsylvania to disclose their fuel mix and key air and other waste emissions to consumers in the form of a label and that the tracking of transactions to support disclosure and labeling should be done by the PJM Independent System Operator ("ISO"). Environmentalists' St. 2, p. 5. OCA witness Barbara Alexander also advocates fuel mix disclosure. OCA St. 5, pp. 29-30.

453. Mr. Biewald's proposal goes beyond the Commission's recently-proposed rules on Customer Information Disclosure for Electricity Providers (52 Pa. Code, Chapter 54, Subpart A), Docket No. L-00970126. Under those rules the source of supply mix must be provided to customers upon request, upon entering into a sales agreement and whenever a significant change occurs in the terms of service. The proposed rules do not require the disclosure of environmental attributes other than fuel mix. These parties' proposals should be rejected.

XIII. Environmental Issues

454. Environmentalists witness David Schoengold proposes that the Commission adopt a plan under which all power purchased in Pennsylvania would have to come from plants meeting the latest environmental standards, Environmentalists' St. 1, p. 37, and notes that other states have enacted similar regulations based on their right to protect the health and welfare of their citizens.

455. Although the Commission retains broad authority to regulate utility service, facility and rate issues, it is the Pennsylvania Department of Environmental Protection and the U.S. Environmental Protection Agency that have the broad authority to implement and administer programs for the protection of the environment, including rules relating to air emissions. It is well established that the Commission does not possess jurisdiction over environmental issues simply because a public utility may be involved. The

Environmentalists' proposal is well beyond the scope of this proceeding and should be rejected.

456. OCA witness Ms. Brockway's suggests that PP&L provide funding of $700,000 for photovoltaic and active solar water heating pilots.

457. Neither the Act nor the Commission's Final Guidelines for Universal Service mandate such pilot programs.[5]

458. Because the annual cost savings would be very low, in light of PP&L's relatively low electric rates, the payback periods would be significant. Most consumers would not be induced to buy a system that required well over a decade to provide benefits.

459. Developing, implementing, and evaluating the OCA's proposed pilots would be time consuming and expensive for the level of benefits received, and therefore should be rejected.

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5 The Commission's Final Guidelines for Universal Service expressly provide that: "Although we believe that research and development are important, we will not direct that universal service and energy conservation funds be spend for research and development. Unlike the California legislature that specifically provided funds for research and development, the Commonwealth's Act gives no direction for such expenditures." Final Guidelines at 6.

PROPOSED CONCLUSIONS OF LAW

1. That the Pennsylvania Public Utility Commission properly has jurisdiction over PP&L, Inc.'s ("PP&L") Restructuring Plan filing at Docket No. R-00973954;

2. That PP&L's Restructuring Plan is fully consistent with the requirements and standards of Section 2804 of the Electricity Generation Customer Choice and Competition Act ("Act"), 66 Pa. C.S. §2804, in that it, inter alia:

   a. Will ensure the continuation of safe and reliable electric service to PP&L's customers;

   b. Is consistent with the implementation schedule set forth in Section 2806 of the Act, 66 Pa. C.S. §2806;

   c. Complies with the rate caps set forth in Section 2804(4) of the Act, 66 Pa. C.S. §2804(4);

   d. Ensures that PP&L will provide transmission and distribution service to all retail electric customers in its service territory and to all alternative generation suppliers, either affiliated or nonaffiliated, on rates, terms of access and conditions that are comparable to PP&L's own use of its system;

   e. Ensures that PP&L's restructuring does not unreasonably discriminate against one customer class to the benefit of another;

   f. Ensures that universal service and energy conservation policies, activities and services are appropriately funded and available in PP&L's territory;

   g. Provides for a competitive transition charge for the recovery of transition or stranded costs in accordance with Section 2808 of the Act, 66 Pa. C.S. §2808;

   h. Ensures an orderly transition to a competitive generation market that protects electric system reliability, is fair to customers and provides PP&L and its investors with a fair opportunity to fully recover its just and reasonable stranded costs;

3. That PP&L's Restructuring Plan is fully consistent with the requirements of Section 2807 of the Act, 66 Pa. C.S. §2807, regarding the obligations applicable to electric distribution companies;

4. That PP&L's claimed stranded or transition costs are known, measurable, just and reasonable in accordance with all requirements of the Act, including Sections 2803 and 2808 (66 Pa. C.S. §§2803, 2808); and

5. That PP&L's Restructuring Plan fully complies with the requirements of Section 2810 of the Act, 66 Pa. C.S. §2810, regarding revenue-neutral reconciliation.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION FOR APPROVAL OF
A RESTRUCTURING PLAN

Docket No R-00973954

TABLES

Dated: February 12, 1998

TABLE A

The following are active parties in Docket No R-00973954:

Office of Consumer Advocate
Office of Small Business Advocate
Office of Trial Staff
Allegheny Power
American Association of Retired Persons
Commission on Economic Opportunity
Delmarva Power & Light
Enron Power Marketing Inc.
Environmentalists
Local 1600, International Brotherhood of Electric Workers
Eric Epstein
Gilberton Power
Mid-Atlantic Power Supply Association
New Energy Ventures
Pennsylvania Petroleum Association
PP&L Industrial Customer Alliance
Schuylkill Energy Resources
United States Department of Defense.

The following are inactive parties in Docket No R-00973954:

Allegheny Electric Cooperative
American Energy Solutions
Anthracite Regional Power Producers
Bethlehem Steel
Center for Energy and Economic Development
Duke Energy Trading Marketing
Dupont Power Marketing
Electric Clearinghouse Inc.
ERI Services Inc.
GPU Energy
Kraft Foods
Noram Energy Management
PECO Energy Company
Pennsylvania Association of Plumbing Heating & Cooling Contractors
Pennsylvania Electric Consumers Council
PP&L Rate Payers Association
Pennsylvania Retailers Association
Vastar Power Marketing

TABLE B

SUMMARY OF
STRANDED COSTS (PUC JURISDICTIONAL)
REVENUE REQUIREMENTS METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Nuclear	$2,824,620		
Fossil	670,016		
NUG	650,960		
Regulatory Assets	354,326		
Total PUC Jurisdictional Stranded Costs - NPV in 1999 Dollars	$4,499,922		

STRANDED COST
CALCULATION - NUCLEAR (PUC JURISDICTIONAL)
REVENUE REQUIREMENTS METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Revenue Required - NPV (1999)	$7,704,351		
Less: Market Revenue - NPV (1999)	4,879,731		
Total PUC Jurisdictional Nuclear Stranded Cost - NPV in 1999 Dollars	$2,824,620		

STRANDED COST
CALCULATION - FOSSIL (PUC JURISDICTIONAL)
REVENUE REQUIREMENTS METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Revenue Required - NPV (1999)	$9,194,236		
Less: Market Revenue - NPV (1999)	(8,524,221)		
Total PUC Jurisdictional Fossil Stranded Cost - NPV in 1999 Dollars	$670,015		

STRANDED COST CALCULATION - NON-UTILITY GENERATION (PUC JURISDICTIONAL) REVENUE REQUIREMENTS METHOD ($000)

	Company Claim	Adjustments	Adjusted Amount
Cost of Purchase - NPV (1999)	$1,141,469		
Less: Market Value - NPV (1999)	(543,374)		
Cost in Excess of Market Value - NPV (1999)	598,095		
Plus: Buy-out Payments - NPV (1999)	52,865		
Total PUC - Jurisdictional NUG Stranded Cost - NPV in 1999 Dollars	$650,960		

STRANDED COST CALCULATION - REGULATORY ASSETS (PUC - JURISDICTIONAL) REVENUE REQUIREMENTS METHOD ($000)

	Company Claim	Adjustments	Adjusted Amount
Unrecovered Energy Costs	$76,815		
Post-Retirement Benefits	8,730		
Susquehanna Operating Costs	9,830		
Common Plant	7,783		
Retired Miners' Healthcare Costs	6,308		
DOE Assessment	16,361		
Deferred Refueling Costs	7,996		
Voluntary Early Retirement Costs	14,085		
Employee Transition Costs	17,106		
Rate Case Expenses	176		
Taxes Recoverable	231,709		
Regulatory Liabilities	(42,573)		
Total PUC Jurisdictional Regulatory Assets Stranded Cost - NPV in 1999 Dollars	$354,326		

TABLE C

SUMMARY OF STRANDED COSTS
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Nuclear	$ 2,528,761		
Fossil	735,571		
Total Generation	3,264,332		
NUGs	650,960		
Regulatory Assets	584,630		
Total NPV as of 1/1/99	**$ 4,499,922**		
PUC Jurisdictional Percent	95.80%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - GENERATION
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Net Book Value	$ 3,820,858		
(Market Value)	(676,969)		
NPV as of 1/1/99	3,143,889		
PV of Nuclear Decommissioning	120,443		
Total NPV as of 1/1/99	**$ 3,264,332**		
Discount Rate	7.92%		
PUC Jurisdictional Percent	95.80%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - NUCLEAR
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Net Book Value	$ 2,554,563		
(Market Value)	(146,245)		
NPV as of 1/1/99	2,408,318		
PV of Nuclear Decommissioning	120,443		
Total NPV as of 1/1/99	**$ 2,528,761**		
Discount Rate	7.92%		
PUC Jurisdictional Percent	95.80%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - FOSSIL
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Net Book Value	$ 1,266,295		
(Market Value)	(530,724)		
Total NPV as of 1/1/99	**$ 735,571**		
Discount Rate	7.92%		
PUC Jurisdictional Percent	95.80%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - REGULATORY ASSETS
ASSET VALUE METHOD
($000)

	Company Claim Gross	Company Claim Net	Adjustment	Adjusted Amount
Unrecovered Energy Costs	$ 80,150	$ 76,815		
Post-Retirement Benefits	14,495	8,730		
Susquehanna Operating Costs	12,836	9,830		
Common Plant Adjustment	18,220	7,783		
Retired Miners' Healthcare Costs	6,582	6,308		
DOE Assessment	22,923	16,361		
Deferred Refueling Costs	8,343	7,996		
Voluntary Early Retirement Costs	15,190	14,085		
Employee Transition Costs	22,279	17,106		
Rate Case Expenses	184	177		
Taxes Recoverable	649,023	496,995		
Regulatory Liabilities	(101,278)	(77,556)		
Total NPV at 1/1/99		**584,630**		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - NUGS
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Cost of Purchases	$ 1,141,469		
Market Value	543,374		
Cost in Excess of Market Value	598,095		
Plus: Buy-out Payments	52,865		
Total NPV as of 1/1/99	**$ 650,960**		
PUC Jurisdictional Percent	97.20%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

TABLE D

COMPARSON OF OCA AND PP&L CALCULATIONS
OF STRANDED COSTS UNDER THE ASSET VALUE METHOD

DESCRIPTION	ASSET VALUE METHOD OCA ASSUMPTIONS	ASSET VALUE METHOD PP&L ASSUMPTIONS	DIFFERENCE OCA AND PP&L ASSUMPTIONS	See Note
NET GENERATION PLANT	$ 3,248,442	$ 3,820,858	$ 572,416	(1)
LESS:MARKET VALUE	3,110,321	676,969	(2,433,352)	(2)
STRANDED GENERATION PLANT	138,121	3,143,889	3,005,768	
REGULATORY ASSETS	259,249	584,630	325,381	(3)
NUG CONTRACTS	574,708	650,960	76,252	(4)
NUCLEAR DECOMMISSIONING	108,125	120,443	12,318	(5)
TOTAL STRANDED COSTS	**$ 1,080,203**	**$ 4,499,922**	**$ 3,419,719**	

Note 1... Net Generation Plant

Jurisdictional Allocation	$ 659,725
CWIP	108,928
Depreciation swap	(196,237)
	$ 572,416

Note 2...Market Value

Plant Retirement	$ 144,881
Coal Price	230,157
Nuclear Capacity Factor	46,679
New CT Fuel	159,298
PJM Imports	226,296
Capacity Prices	38,446
Inflation Adjustment	198,583
A&G Expense	402,735
Fossil Decommissioning	315,867
Productivity Factor	66,162
Keystone/Conemaugh Lives	71,281
Taxes Other Than Income	133,795
Discount Rate	135,346
Jurisdictional Allocation	(336,609)
Land Escalation	78,045
Capital Additions	165,318
Deferred Income Tax Adjustment	281,671
Discount Method	71,072
Miscellaneous Adjustments	4,330
	$ 2,433,352

Note 3...Regulatory Assets

Taxes Recoverable	$ 230,304
Unrecovered Energy Costs	60,570
DOE Assessment	16,361
SSES Deferred Refueling Costs	7,996
Employee Transition Costs	14,540
Adj Req. OCA Original to Surrebuttal	(29,585)
Jurisdictional Allocation	40,367
Rate Case Expenses	177
Discount Rate	(9,534)
Discount Method	(5,815)
	$ 325,381

Note 4... NUG Contracts

Capacity Adjustment	$ 56,911
OCA Pricing	35,487
Jurisdictional Allocation	4,068
Discount Rate	(11,232)
Discount Method	(8,982)
	$ 76,252

Note 5...Nuclear Decommissioning

Jurisdictional Allocation	$ 20,864
Discount Rate	(647)
Discount Method	(7,899)
	$ 12,318

NOTES TO TABLE D

Table D provides a reconciliation of the PP&L and OCA calculation of stranded costs using the OCA's asset value method. The table starts with "Net Generation Plant" and subtracts "Market Value" to obtain "Stranded Generation Plant." The table then adds "Regulatory Assets," "NUG Contracts," and "Nuclear Decommissioning" to arrive at "Total Stranded Costs." Column 1 sets forth the OCA claim; Column 2 sets forth the PP&L claim; and Column 3 sets forth the difference between the two claims.

The Table also contains five "Notes" which provide a detailed reconciliation of the differences between the PP&L and OCA cases on Net Generation Plant, Market Value, Regulatory Assets, NUG Contracts and Nuclear Decommissioning. The following discussion summarizes each adjustment and provides a cross-reference to where the issue is addressed in PP&L's Brief.

Note 1 — Net Generation Plant

Jurisdictional Allocation. PP&L adjusts its jurisdictional allocation to reflect expiring wholesale contracts. OCA freezes the jurisdictional allocation at January 1, 1996 and ignores subsequent changes. This issue is addressed in Section V.A.

CWIP. PP&L adjusts the plant in service balance to reflect estimated plant in service at January 1, 1999. OCA does not make this adjustment. This issue is addressed in Section V.D.5.

Depreciation Swap. PP&L proposes to transfer excess T&D depreciation reserve to generation, thereby reducing stranded costs as contemplated by the Act. The OCA opposes this adjustment and thereby shows a higher net generation plant value. This issue is discussed in Section II.D.2.b.

Note 2 - Market Value

Plant Retirement. PP&L's market revenue calculation reflects the retirement of its generating plants at the end of their book lives. OCA indefinitely extends the lives of PP&L's coal plants. This issue is addressed in Section IV.C.2.e.vii.

Coal Price. OCA projects increasing gas prices and an ever widening gap between gas and coal prices. PP&L asserts that OCA's gas prices are too high and that there is no support for the divergence between gas and coal prices. This adjustment shows the effect of using OCA's gas prices and escalating coal prices at the same rate as gas prices after 2000. This issue is addressed in Section IV.C.2.a.ii.

Nuclear Capacity Factor. PP&L uses a nuclear capacity factor of 78% in its market price projection. OCA uses 75%. This issue is addressed in Section IV.C.2.e.i.

New CT Fuel. The OCA market price forecast assumes new combustion turbines will burn 50% gas and 50% oil. PP&L projects that the new CTs will burn the least expensive fuel. This issue is discussed in Section IV.C.1.a.

PJM Imports. OCA assumes a significant decline in PJM imports after 2005. PP&L does not. This issue is addressed in Section IV.C.1.a.

Capacity Prices. PP&L and OCA disagree on future market prices for capacity. This issue is addressed in Section IV.B.2.

Inflation Adjustment. PP&L employs a 2.5% inflation assumption in its market price forecast. OCA uses a higher rate. This issue is addressed in Section IV.C.2.b.

A&G Expense. PP&L allocates A&G expenses using the cost allocation factors from the cost allocation study approved by the PUC in its 1995 base rate case. OCA, without discussion, reduces generation-related A&G by $402.7 million. This issue is addressed in Section V.D.1.

Fossil Decommissioning. In accordance with the Act, PP&L claims its fossil decommissioning expense as a stranded cost. OCA opposes this claim. This issue is addressed in Section V.C.4.

Productivity Factor. OCA proposes to reduce future O&M expenses to reflect improved productivity. PP&L asserts it has already reflected such improvements. This issue is addressed in Section V.D.2.

Keystone/Conemaugh Lives. PP&L uses its book lives for the Keystone and Conemaugh plants. OCA proposes a life extension. This issue is addressed in Section V.C.10.

Taxes Other Than Income. PP&L projects that taxes other than income will increase at the rate of inflation. OCA proposes flat taxes. This issue is addressed in Section V.C.3.

Discount Rate. PP&L uses a discount rate equal to its weighted average after-tax cost of capital, including an 11.5% return on common equity, as approved by the PUC in PP&L's 1995 base rate case. OCA proposes a 10% ROE. This lower rate increases the net present value of market revenue and correspondingly decreases stranded costs. This issue is addressed in Section V.B.1 and Section VI.

Jurisdictional Allocation. This is the same issue discussed in Note 1. The combination of the OCA's higher market price and lower jurisdictional allocation decreases market revenue by $336.6 million. This increase partially offsets increases in stranded generation plant ($659.725 million), stranded regulatory assets ($40.367 million), stranded NUG contracts ($4.068 million) and stranded nuclear decommissioning ($20.864 million) caused by the OCA's constant jurisdictional allocation. This issue is addressed in Section V.A.

Land Escalation. OCA includes an estimate of land value as an offset to stranded costs. PP&L asserts that the OCA claim is overstated. This issue is addressed in Section V.D.3.

Capital Additions. OCA treats capital additions as operating expenses, thereby understating tax expense and overstating market value. This issue is addressed in Section V.D.4.

Deferred Income Tax Adjustment. OCA fails to properly reflect deferred taxes and thereby understates asset value. This issue is addressed in Section V.D.7.

Discount Method. PP&L discounts to present value on a monthly basis. OCA discounts on a semi-annual basis. Applied to market value, the monthly method decreases net present market value and increases stranded costs.

Miscellaneous Adjustments. This is a fallout figure for other unexplained differences in PP&L and OCA models.

Note 3 — Regulatory Assets

Taxes Recoverable. PP&L calculates taxes recoverable over the seven-year CTC period consistent with the PECO decision. OCA does not. This issue is addressed in Section V.D.6.

Unrecovered Energy Costs. PP&L's stranded cost claim includes unrecovered energy costs deferred pursuant to PUC Order. OCA opposes this claim. This issue is addressed in Section V.C.1.

DOE Assessment. OCA identifies a double count in PP&L's claim. PP&L does not contest this adjustment, which is discussed in Section V.C.7.

SSES Deferred Refueling Costs. PP&L has recorded as a regulatory asset the cost of the first Susquehanna refueling outage which was not reflected in rates. OCA opposes the claim. This issue is addressed in Section V.C.7.

Employee Transition Costs. PP&L claims certain employee transition costs as a stranded cost in accordance with the Act. OCA opposes this claim. This adjustment is addressed in Section V.C.2.

Adjustment to OCA Surrebuttal. In its rebuttal case, PP&L makes a $27.8 million downward adjustment to its claim to adjust taxes reconcile for the T&D depreciation reserve swamp. OCA does not incorporate this concession in its surrebuttal.

Jurisdictional Allocation. This is the same issue discussed in Note 1. PP&L's higher jurisdictional allocation increases jurisdictional regulatory assets. This adjustment is addressed in Section V.A.

Rate Case Expense. PP&L has recorded a regulatory asset for unrecovered rate case expense. OCA opposes this adjustment. This adjustment is addressed in Section V.C.11.

Discount Rate. This is the same issue discussed in Note 2. Here, the OCA's lower discount rate increases the present value of the regulatory asset and increases stranded costs. This issue is addressed in Section V.B.1 and VI.

Discount Method. This is the same issue discussed in Note 2. Here, the OCA's semi-annual method increases the present value of the regulatory asset and increases stranded costs. This issue is addressed in Section VI.B.2.

Note 4 — NUG Contracts

Capacity Adjustment. PP&L uses a NUG capacity factor of 90% to project NUG output. OCA uses a lower figure. This issue is addressed in Section IV.C.2.e.v.

OCA Pricing. The OCA uses a higher market price than PP&L. This decreases NUG stranded costs. This issue is addressed in Section IV.

Jurisdictional Allocation. This is the same issue addressed in Notes 1,2,3. The OCA's use of a lower jurisdictional allocation decreases the jurisdictional share of NUG contracts and decreases jurisdictional stranded costs. This issue is addressed in Section V.A.

Discount Rate. This is the same issue discussed in Notes 2 and 3. The OCA's use of a lower discount rate increases the net present value of NUG contract payments and increases stranded cost. This issue is addressed in Section V.B.2 and VI.

Discount Method. This is the same issue discussed in Notes 2 and 3. Here, the OCA's semi-annual method increases the present value of NUG payments and increases stranded costs. This issue is discussed in Section VI.B.2.

Note 5 — Nuclear Decommissioning

Jurisdictional Allocation. This the same issue discussed in Notes 1, 2, 3, and 4. The OCA's use of a lower jurisdictional allocation decreases the jurisdictional share of nuclear decommissioning costs and decreases jurisdictional stranded costs. This issue is addressed in Section V.B.5.

Discount Rate. This is the same issue addressed in Notes 2, 3 and 4. The OCA's use of a lower discount rate increases the net present value of nuclear decommissioning stranded costs. This issue is addressed in Sections V.B.1 and VI.

Discount Method. This is the same issue addressed in Notes 2, 3 and 4. The OCA's use of a semi-annual method increases the net present value of nuclear decommissioning stranded costs.

TABLE E

($ Billions)

NPV of PP&L Recoverable Stranded Costs as of 1/1/99 (Tr. 964 (8/20/97))	$	4.026
Less Gross Receipts Tax @ 4.4%		(0.177)
Taxable Recoverable Stranded Costs		3.849
Less Taxes on Stranded Cost Recovery @ 41.5% Effective Tax Rate (PP&L Exh. JRS 1)		(1.597)
After-Tax Recoverable Stranded Costs		**2.252**

TABLE F

PP&L Pre-Tax Cost of Capital

	Ratio	Cost	Weighted Cost	Tax Adjustment	Pre-tax Cost
Debt	47.0%	7.89%	3.71%	0.00%	3.71%
Preferred	7.8%	7.10%	0.55%	0.39%	0.95%
Equity	45.2%	11.50%	5.20%	3.69%	8.88%
Total Cost			9.46%	4.08%	**13.54%**

Allowed Return to Total Capital of 7.89%

	Ratio	Cost	Weighted Cost	Tax Adjustment	Pre-tax Cost
Debt	47.0%	7.89%	3.71%	0.00%	3.71%
Preferred	7.8%	7.89%	0.62%	0.44%	1.05%
Equity	45.2%	7.89%	3.57%	2.53%	6.10%
Total Cost			7.89%	2.97%	**10.86%**
EffectiveTax Rate	41.4935%				

Note: Based on PP&L Exh. JRS1, Tab A, Attachment 1.

ORIGINAL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Pennsylvania Power & Light Company For Approval of Its Restructuring Plan Under Section 2806 of the Public Utility Code	:	Docket No. R-00973954

CERTIFICATION OF SERVICE

I hereby certify that on February 12, 1998, I served a true copy of the Post-Hearing Brief of PP&L, Inc. upon counsel for the active participants, listed below, in accordance with the requirements of 52 Pa. Code § 1.54 (related to service by a participant):

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