Pennsylvania Power & Light Company

Rebuttal Testimony

Volume 1

Docket No. R-00973954

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Pennsylvania Power & Light Company
Docket No. R-00973954
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 1-R

Rebuttal Testimony of Joseph P. Kalt, Ph.D.

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Joseph P. Kalt. My business address is the Economics Resource Group, One Mifflin Place, Cambridge, Massachusetts, 02138.

Q: Have you provided testimony previously in this proceeding?

A: Yes. I provided written direct testimony on April 1, 1997 on behalf of Pennsylvania Power & Light Company (PP&L or the Company) in a statement designated as "Pennsylvania Power & Light Statement No. 1." The primary focus of my direct testimony was to articulate the conditions necessary to restructure the electric power industry consistent with sound economic and public policy principles, and to assess the Company's filing in this proceeding in light of these principles.

Q: Please describe the purpose of your rebuttal testimony.

A: In this statement, I address a number of concerns and questions raised by various other parties ("intervenors") regarding PP&L's proposals for implementing restructuring consistent with

Pennsylvania's 1996 Electricity Generation Customer Choice and Competition Act (Act). In particular, my analysis here focuses on matters related to the protection and promotion of competition in non-monopoly services, PP&L's proposals affecting the recovery of costs "stranded" as a result of the pending regulatory reforms, and rate designs proposed by the Company for purposes of affording the opportunity to recover certain of its stranded costs. Specifically, I address points and themes raised by such intervenor witnesses as: Michael D. Dirmeier, John W. Mayo and Richard S. Shapiro (on behalf of Enron Power Marketing Inc.); Robert D. Knecht (on behalf of the Office of Small Business Advocate); Bruce Biewald and Peter A. Bradford (on behalf of the Environmentalists); Donald E. Johnstone (on behalf of the Mid-Atlantic Power Supply Association); Stephen J. Baron (on behalf of PP&L Industrial Customer Alliance); Nancy I. Day (on behalf of New Energy Ventures); and Barbara Alexander (on behalf of Office of Consumer Advocate).

Q: Please summarize the conclusions of your testimony.

A: My primary conclusions are as follows:

- **Promoting and Protecting Competition:** The overriding objective of providing consumers with the benefits of an efficient electric power industry entails the design of public policies that promote and protect competition. Given the basic structure of the industry envisioned in the Act, with competition to be introduced into the supply and marketing of electric power while maintaining the regulated monopoly status of power transmission and distribution services, the clear challenge for sound policy is to develop measures that prevent elements of continuing regulated monopoly from adversely affecting competition in the non-monopoly activities.

- **The Limits of Sound Competition Policy:** Sound policy should be aimed at preventing anticompetitive use of an incumbent utility's still-regulated monopoly functions to stifle competition in the non-monopoly functions. A number of the intervenors, however, recommend steps that would have the effect of handicapping the incumbent utility's ability to compete in the non-monopoly activities and/or artificially supporting the status of the incumbent's rivals. Such promotion and protection of *competitors*, however, would come at the expense of the process of *competition* and, ultimately, the consumer. *Sound policy should reject such approaches.*
- **The Process of Policy Reform:** As justification for policies that would handicap the incumbent, a number of the intervenors raise the specter of a litany of anticompetitive consequences that might result from the vertical integration of an incumbent utility's monopoly and non-monopoly functions, and urge the Commission

to adopt draconian measures to protect against asserted prospective abuses. While such an approach would clearly benefit the incumbent's rivals, "convicting" the incumbent of innumerable misdeeds before the fact is inappropriate policy. Such an approach would deny the consumers the opportunity to benefit from the competitive strengths that an incumbent can bring to the marketplace and would tend to eliminate efficiencies in the incumbent's operations. Proper policy at this time entails the implementation of safeguards, codes of conduct, incentives, and regulatory oversight that operate to prevent abuse of utilities' remaining monopoly functions. The process that the Commission has implemented with this and related proceedings moves in this very direction.

- **PP&L's Proposals:** Working within the rules, regulations, directives, and spirit of both the Act and concomitant federal policies, PP&L is putting forth a set of far-reaching proposals for ensuring its compliance with principles calling for competitive, unbundled provision of electric power to consumers. These steps include functional separation of the Company's monopoly and non-monopoly functions, open and non-discriminatory access to the Company's still-regulated monopoly functions, codes of conduct governing the separation of monopoly and non-monopoly functions, and rate designs that obviate cross-subsidization or self-favoritism of PP&L's non-monopoly power supply business. My assessment of PP&L's proposals are that they are consistent with the policy objectives of the Act, will protect and promote competition in non-monopoly services, and are workable.

- **Stranded Cost Recovery:** Notwithstanding the Act's provision allowing Pennsylvania utilities' the opportunity to recover costs otherwise stranded by industry restructuring, a number of intervenors seek limits on and/or the elimination of this opportunity. As discussed at length in my direct testimony, denying affected utilities the real opportunity to recover their stranded costs is inconsistent with sound economic policy for the Commonwealth. Intervenors' challenges to PP&L's design of rates and, particularly, its competitive transition charge (CTC) are similarly unwarranted. PP&L's CTC design provides the Company with the opportunity -- but not the guarantee -- of substantial stranded cost recovery while, at the same time, improving price signals for consumers and satisfying the Act's requirements for rate stability and no cost shifting.

II. FRAMEWORK FOR COMPETITION POLICY

Q: Prof. Kalt, what is the role of competition in promoting the interests of consumers?

A: Under the appropriate circumstances, competition yields consumers the products they want at the lowest sustainable prices at which those products can be produced. These consumer benefits come about in competitive markets because competition fosters *efficiency*. That is, the force of competition tends to drive firms to operate at minimum feasible cost (productive efficiency), to deliver products and services to the consumers that value them the most (distributive efficiency), to produce the mix of products and services most desired by consumers (allocative efficiency), and to innovate and improve products and services over time (dynamic efficiency).

Q: In your opinion, should the Commission undertake policies to enhance or encourage competition in Pennsylvania's electric power industry?

A: Yes. The appropriate approach, as set forth in the Act and related federal policies, is to promote competition in the generation and marketing of electricity, where the cost structures of power generation and marketing make it feasible for numerous firms to flourish. At the same time, however, certain functions such as transmission and distribution may be subject to cost structures that yield elements of natural monopoly (i.e., with one large firm having lower costs of production than a combination of smaller firms), or policy considerations may impose special responsibilities on a particular firm (such as the supplier of last resort requirement borne by PP&L). Under such conditions, continued monopoly status is rational policy, and calls for regulation of rates and operations. This, of course, is the basic structure for policy reform that the Act envisions.

II.A The Design of Competition Policy for a Restructured Electric Power Industry

Q: What public policy steps are needed to make the industry structure you have just outlined operate so as to ensure that the consumer benefits?

A: The answer to this -- and the crucial elements of a policy framework for the Commission -- follow from recognition of the ways in which the development of a competitive marketplace in electricity supply (both wholesale and retail) can be thwarted. *First*, competition will not flourish if public policy continues to protect the traditional service area franchises of utilities by blocking entry by rivals. *Second*, with transmission and distribution functions subject to natural monopoly and continuing regulation, rivals in the wholesale and retail supply of electricity cannot really compete if they cannot get on the transmission and distribution lines and reach supply sources and customers. *Third*, rivals to incumbent utilities may be effectively precluded from competing if an incumbent utility in control of transmission and distribution can utilize the monopoly status of these functions to disadvantage or block the competition of rivals through cross-subsidization of the utility's non-monopoly supply services, discriminatory treatment of rivals' use of transmission and distribution services, or the conditioning ("tying") of a customer's access to transmission and distribution on purchase of the utility's non-monopoly service(s).

Among the participants in the present restructuring efforts there is not serious disagreement that the foregoing are the categories of things that might go wrong in the effort to introduce competition into electricity supply. The serious discussion centers on the appropriate policies to deal with these potentialities. In fact, consideration of these three basic challenges to effective reform suggests the scope of proper Commission policy.

The Commission (in concert with the Federal Energy Regulatory Commission) needs to: (1) remove legal or regulatory impediments to the entry of new firms into the supply sector of the market (minimum requirements necessary to ensure that the market functions smoothly and reliably); (2) ensure that competing firms and their customers have access to the regulated monopoly services of PP&L on a non-discriminatory, non-conditioned, and comparable basis; and (3) ensure that competition in non-monopoly activities is not thwarted by cross-subsidization of such activities (e.g., by shifting costs of such activities into regulated rates for monopoly functions).

Q: If the participants in the present policy debates do not disagree with the basic economics of competition analysis in the restructured industry, what separates the various interested parties?

A: Given the foregoing policy guidelines, I read the various exchanges of the parties as focusing debate on the philosophy of policy design that the Commission should adopt. In particular, I think three options are before the Commission.

1. **Prevent Extension of Remaining Monopoly Power:** PP&L's approach (and the approach embodied in the FERC's reliance on codes of utility conduct, failure to force divestiture of vertically integrated electric utility companies, etc.) embodies the principle that the appropriate public policy is to ensure non-discriminatory access by all viable competitors into unregulated markets, and to regulate only relations between regulated utilities and their unregulated affiliates. Actions and advantages of the unregulated affiliates of an incumbent utility that should

be regulated or eliminated are solely those that derive from leveraging of continued ownership and control of monopoly functions (i.e., transmission and distribution). Actions and advantages not so derived represent the tools of competition *that the unregulated affiliates bring to non-monopoly* marketplaces, and the consumer will be harmed if denied access to these.

2. **Handicap the , on behalf of Enron, Non-Monopoly Affiliates:** Witnesses such as Mr. Dirmeier essentially argue for the regulatory elimination of perceived advantages that non-monopoly affiliates of PP&L might have as a prerequisite for allowing such affiliates to compete in newly competitive markets. Thus, Mr. Dirmeier recommends, for example, limitations and (in his view) preferably prohibitions on the use of the PP&L name and trademarks by the electric distribution company ("EDC") affiliates -- viewing such assets as giving the affiliates an advantage with consumers who value the PP&L name and reputation. Similarly, Mr. Dirmeier (at 24-25, 44-47) and Prof. Mayo (at 31) would take steps to sever goodwill between PP&L and its customers that otherwise might incline customers to stay with a PP&L affiliate as their electricity supplier. More generally, the imposition of detailed state marketing restrictions on the

affiliates of incumbent utilities would handicap those affiliates as competitors by subjecting them to complex and cumbersome reporting, operational, and compliance specifications not shared by their rivals. This would enhance the fortunes of PP&L's rivals, but would not promote the interests of consumers.

3. **Affirmatively Support or Subsidize Rivals:** The other side of the coin that handicaps incumbents as competitors would have the Commission take affirmative steps to support rivals of the incumbent. The putative purpose would be to provide offsets to asserted advantages of size, longevity, name recognition, and the like that the incumbent might be thought to bring to the marketplace. Thus, for example, Mr. Dirmeier would require PP&L to open up any pre-existing market-priced contracts with customers (if such contracts existed) to access by rivals upon the commencement of direct access, thereby creating an additional target customer base for rivals. More generally, complex and cumbersome marketing restrictions that raise the costs of the incumbent or deny the incumbent the use of assets that consumers value (such as brandname) are the functional equivalent of a subsidy to rivals, who do not have to bear such costs or build up such assets to remain competitive in the

marketplace. This policy strategy is consistent with the interests of PP&L's rivals, but not the interests of consumers.

Q: Which of these three approaches is best suited to achieving the objective of producing benefits for the consumer through restructuring?

A: The first approach is the proper stance for the Commission to take. It is aimed directly at the kinds of issues that the vertical integration of regulated monopoly functions and unregulated non-monopoly functions raises. It clearly implies, for example, that PP&L and other incumbent utilities that operate transmission and distribution systems should not be permitted to cross-subsidize their non-monopoly generation and sales functions by shifting costs of such functions into regulated transmission and distribution rates, or to deny access on comparable terms and conditions to their regulated monopoly services, or to condition such access on purchase of unregulated non-monopoly electric supplies. It also implies that information acquired in the course of conducting regulated monopoly functions not be provided on a discriminatory basis to non-monopoly affiliates, and that such activities as discriminatory joint marketing of monopoly and non-monopoly services or "channeling" of monopoly transmission or distribution customers to non-monopoly affiliates are inappropriate. Importantly, the functional separation and accompanying codes of conduct set forth by the Company in its FERC filings and in its Retail Access Code of Conduct provide for precisely these protections and are properly subject to oversight by the Commission.

Q: But, in order to foster competition, doesn't the Commission have to eliminate any advantages that PP&L might have in the competitive market for electricity supply -- *per* the second approach you have outlined above?

A: No. Such a conclusion does not follow if the Commission's goal is to benefit consumers, rather than particular competitors in the marketplace. In fact, such a conclusion confuses the nature of competition. Notwithstanding simplified models we economists use as pedagogical tools with undergraduates -- models in which every firm is identical with every other firm -- advantages and disadvantages that may exist across firms are not inimical to well-functioning competitive markets. Indeed, competition in the real world is a process of dynamic search for and destruction of advantages, as rivals try innumerable approaches to attract customers to their products.

At any point in time in any competitive market, individual firms have advantages of various sorts over their competitors, either by virtue of luck, savvy, or history. Some firms have brand names that are well-respected, others have convenient locations that reduce transportation costs, others have a base of potential customers encountered in related markets, and others have accumulated expertise in how to attack the problem of attracting customers. The reason that such factors are advantages is because they allow the firm that possesses them to deliver something that consumers want, or to deliver what consumers want on better terms.

In theory, regulators could "handicap" the "competition" by forbidding the use of brand names, imposing a tax on firms with low transportation costs, etc. If this were a game and the regulators' purpose was to give everyone the same chance of winning, that would make sense. But this is not a game, and the regulators shouldn't care which competitors "win" at any particular time so long as consumers benefit. The process of rivals each trying to find their own advantages and overcome the advantages of their competitors is what allows consumers to "win."

As applied to PP&L, so long as the Company provides non-discriminatory access to regulated facilities, and does not engage in cross-subsidy, then any advantages it has in the marketplace derive from its ability to give consumers something they want. To take away these advantages is to reduce the ability of PP&L, and hence the market as a whole, to deliver benefits to consumers.

Q: Should the Commission be worried that PP&L possess advantages -- say, its brand name or its contacts with an existing customer base -- that would make it infeasible for rivals to compete and survive at all?

A: I do not believe that such a notion has any support. Attributes such as brand names or reputations with consumers are themselves directly subject to competitive challenge, and the process of competition turns good reputations into bad reputations if the company in question does not back up the assurances of quality that customers infer from brand names and the like. The fates of bankrupt firms -- such as Eastern Airlines and K-Mart -- with historically strong names and large customer bases attest to this process. If Mr. Dirmeier is right that PP&L will use its brand name "to imply to customers that its product will be better" it is the process of competition by which rivals will demonstrate "but not as good as mine."

It is not plausible that the prospective entrants into electricity supply markets lack the capacity to find advantages of their own that PP&L will have difficulty matching and that will enable such new rivals to compete vigorously against the incumbent's strengths. Prospective new entrants range from aggressive smaller entrepreneurial firms to large firms with well-established brand names and expertise at chasing customers. These include numerous other vertically integrated utilities originally hailing from other jurisdictions, independent power producers and marketers, dynamic energy service firms such as Enron, and retailing companies such as American Express, Citicorp, Fidelity Investments, and General Electric that have expressed interest in entering electricity markets.[1] Already in the PJM area, approximately 50 firms have registered as members of PJM, with the reasonable presumption being that most of them have intentions of participating in the marketplace in which PP&L will operate. As shown in Exhibit JPK 2, the members of PJM include many who rival or outrank PP&L in size, experience, and even perhaps name recognition. To date, at least fifteen firms are licensed to be alternate retail suppliers under the Act.

It is also relevant to point out that PP&L is likely to enter the non-monopoly marketplaces with relative weaknesses, as well as some strengths. As many natural gas companies learned upon introduction of open access on pipelines and competition in the resale of gas, decades of insulation from competition create challenges of organization, expertise, and even corporate culture that are difficult to overcome quickly. The kinds of rivals that PP&L will encounter (see Exhibit JPK 2) include companies with considerably more experience and success in unregulated markets or in markets with partial

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[1] "Power Players," *Forbes*, May 19, 1997.

deregulation of the general form contemplated by the Act (including natural gas and oil pipelines). Some of these rivals, such as Enron, have a significantly larger assets base and earn substantially more revenue than PP&L.

Q: If PP&L does have some advantages from, say, its brand name and reputation with customers, and those advantages derive from a time in which the Company was more insulated from competition, is it proper that PP&L will be able to tap into those advantages as it meets the competition in the restructured market setting?

A: From the point of view of consumers' interests, it is not relevant when PP&L may have developed particular competitive strengths. Irrespective of their historic origins, advantages that a company such as PP&L may realize as competition takes hold are advantages because consumers place value on the attributes brought to the market by the Company. To take such advantages out of the marketplace by regulatory fiat impedes the competitive process and is deleterious to consumers. In fact, it is for this reason that antitrust economics provides no support for handicapping firms with competitive advantages that derive from consumer preferences (including the quality assurance role of reputational assets). Rather, the proper inquiry of competition policy as applied to incumbent electric utilities is whether they can exercise anticompetitive influence in non-monopoly markets as a result of their continued presence in monopoly markets. In other words, what policy should be concerned about is not that incumbent utilities will come to the competitive game with advantages that enable them to effectively provide what consumers want, but rather that incumbent utilities might turn their monopoly status in transmission and distribution to anticompetitive effect in non-monopoly electricity supply markets.

Q: What about the policy of supporting or effectively subsidizing rivals? Shouldn't the Commission try to promote an increasing number of competitors in order to promote competition?

A: The positive role for the Commission is in breaking down legal and regulatory barriers to entry, in ensuring non-discriminatory access, and preventing cross-subsidization of incumbent utilities' non-monopoly activities by their monopoly activities. Under such policies, market forces will determine how many competitors succeed by efficiently meeting customers' needs. The evidence is strong that under such policies, competition will be vigorous. At the wholesale level, the FERC has recently provided initial approval for market-based pricing by PP&L based on analyses demonstrating PP&L's lack of market power and lack of affiliate abuse,[2] and the entire thrust of FERC's efforts regarding power pools and wholesale generation is aimed at ensuring competitive conditions. With a competitive wholesale market and non-discriminatory access to retail customers, retail competition in Pennsylvania can be expected to be highly robust. When retail sellers can readily acquire supplies in the wholesale market and their access to transmission and distribution is assured, the entry of retail competitors will be easy and will provide potent competitive discipline on PP&L and all others in the market. As suggested by the experience in other states and the nature of the participants indicated in Exhibit JPK 2, the prospect of anticompetitive market power in retail sales is not realistic.

For the Commission to go beyond the roles of ensuring access, preventing cross-subsidization, and removing legal and regulatory entry barriers into non-monopoly electricity sales is poor competition policy and inconsistent with consumers' interests. The number of competitors is not the proper target. Competition is a process, and policy should be designed to foster a competitive process by

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[2] *Order Conditionally Accepting for Filing Proposed Market-Based Rates*, 80 FERC ¶ 61,053 (July 17, 1997). These determinations are contrary to Prof. Mayo's assertions that PP&L will have generation market power in the restructured environment, albeit Prof. Mayo has provided no evidence by which to assess his assertions (at 6-7). Similar assertions are made by Mr. Johnstone, albeit also without provision of evidence (starting at 3).

preventing the abuse of monopoly status that will still reside in transmission and distribution services. To pursue numbers for numbers sake is to promote the survival of rivals who cannot make it in a competitive environment. The stake that all Commonwealth citizens have in a healthy economy for Pennsylvania is not promoted by policies that require the support of inefficient businesses.

II.B Implementing Functional Separation Policies

Q: How can a policy of separating monopoly and non-monopoly functions of an incumbent utilities be implemented?

A: The most draconian approach would be to force the divorcement of monopoly and non-monopoly lines of business through divestiture. Divestiture clearly achieves the goal of separation, but (as discussed in my direct testimony) it does so at significant loss of those efficiencies present in the economies of scope exhibited by integrated utilities. In fact, Mr. Dirmeier recognizes that there are such economies, although he concludes that such economies can be sacrificed to the Act's pro-competitive ends (at 24). He further concludes that divestiture "may be necessary if a level playing field is ever to be achieved" (at 21). This parallels the conclusion of Prof. Mayo, who describes divestiture as a "structural separations approach" (at 17). Notwithstanding these conclusions, the Act sets out the challenge of trying to meet the goals of competition in electricity supply without the sacrifices that divestiture would entail. In my view, the Act has set out a challenge that can be met.

Q: What alternatives are there to divestiture?

A: When all is said and done, the alternatives boil down to mixtures of regulatory rules, incentives, and oversight aimed at ensuring against the anticompetitive use (abuse) of relationships between monopoly and non-monopoly functions of the integrated utility. The task of sound policy is find the mixture of rules, incentives, and oversight that adequately ensures competitive performance, without unduly handicapping the incumbent's ability to compete to provide what consumers want and without artificially attempting to support rivals at the expense of the competitive process. Below I discuss the basic elements required of both the regulator and the incumbent utility consistent with this approach.

Q: Prof. Mayo asserts that there is a third approach -- what he calls "competition enabling" -- to ensuring the competitive performance of incumbent utilities. Do you concur?

A: I do not think that Prof. Mayo's "competition enabling" approach assists us in designing sound policy for regulating the matters raised by the integration of still-regulated monopoly and unregulated non-monopoly functions within utilities. As I understand his framework, the cornerstone of "competition enabling" is that "regulators must tenaciously and at every opportunity seek to eliminate all regulatory and legal impediments to entry" (at 19). Prof. Mayo opines that "regulatory rules...will ultimately succumb to the ingenuity of the vertically integrated firm to devise mechanisms that enable it to circumvent the rules and thereby exploit and/or extend its monopoly power" (at 19). He sees entry and the threat of entry into formerly monopolized markets as the only way (apparently short of divestiture) to eradicate problems of affiliate abuse (at 19-20, 23-25).

Depending on how we look at Prof. Mayo's "competition enabling" admonitions, they are either flawed, contradictory, or add nothing to our understanding of the proper design of regulatory policy. By "flawed" I mean that, as important as the elimination of regulatory and legal barriers to entry is to promoting competition in non-monopoly services, the elimination of such impediments to entry is not likely to eliminate the problems of natural monopoly that arise from the cost structures of transmission and distribution of electricity. That is, even with unimpeded entry, single large systems can generally be presumed to be more efficient than a multitude of duplicative smaller systems, and the single large firm can be expected to survive and dominate even in the face of no entry barriers. Thus, easy entry into other functions (such as electricity generation and/or retail marketing) does not stop the naturally monopolistic owner of transmission and distribution from engaging in discriminatory practices that favor its generation or marketing, if unchecked by regulation.

Prof. Mayo does assert that the regulator must "protect" competition in formerly monopolized markets so long as monopoly functions remain integrated into incumbent utilities (at 19). He then goes on to recommend a number of rules for governing the relationship between monopoly and non-monopoly activities, including prohibitions on bundling of monopoly and non-monopoly activities (at 26),[3] and the regulation of rates if it is determined that such functions are not competitive (at 27). In calling for stout rules governing still-monopolized functions and their relationships with non-monopoly functions, Prof. Mayo, of course, contradicts his admonition that rules are inevitably circumvented.

Ultimately, I believe Prof. Mayo's recommendations amount to a description of the process that the Commission, PP&L, and other parties have already recognized and adopted. In calling for "protections" against affiliate abuse and monopoly leveraging, he has

[3] Apparently, even when the activities are otherwise available on an unbundled basis.

described the very task that the Commission and PP&L have undertaken in this proceeding. In calling for the continued regulation of functions that are determined to be insufficiently competitive (at 23-24), Prof. Mayo has recognized why the Commission and PP&L do not call for the deregulation of transmission and distribution rates. In calling for the Commission to assess if and how the retail-stage can be competitive, he has described efforts the Commission is engaged in here, in its Competition Safeguards Working Group, and the kind of effort the FERC engages in when determining the viability of market-based rates.

Q: Prof. Mayo (along with Ms. Day and Mr. Johnstone) also calls for the unbundled and non-monopoly provision of "revenue cycle services" associated with billing, metering, meter reading, and the like. Is this a necessary component of the Act's goal of introducing customer choice and competition into electricity supply?

A: No. While separate arguments might be made as to why such services should be subjected to unbundling and competitive provision by multiple suppliers, such a step is not a prerequisite for creating effective competition in wholesale and retail electricity supply. Maintaining such functions as *regulated* monopoly functions within the distribution arm of PP&L does mean that they should be provided on a comparable non-discriminatory basis to all market participants, and PP&L's code of conduct and the Commission's oversight should ensure that such services are not utilized anticompetitively to inhibit the effectiveness of rivals.

In the case at hand, a number of factors have influenced the decision to have PP&L continue to offer revenue cycle services on a regulated, monopoly basis. First, the Company bears a number of obligations under 52 Pa. Code, Chapter 56 that make it responsible for connection and disconnection of service, assurance of the quality of residential service, termination of service, and the like; and the Company stands as the supplier of last resort for customers who do not elect to take supply from competitors.[4] Under such conditions, prospects of weakened lines of accountability, customer confusion, and transactions costs make the provision of revenue cycle services by potentially all independent suppliers far less straightforward than implied by Prof. Mayo. At any rate, as I have noted, competitive provision of revenue cycle services is not required in order for competition to be introduced into supply services.

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[4] See, e.g., *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. §2807(E) and (F)*, Pa. PUC Docket No. M-00960890F.0011 (July 11, 1997).

To the extent that revenue cycle services (and, indeed, any services provided pursuant to PP&L's Chapter 56, supplier of last resort, and similar obligations) remain within PP&L's distribution function, they are subject to just and reasonable rate standards and non-discrimination provisions applicable to monopoly activities. This assures protection of the consumer and polices the use of such services as mechanisms of anticompetitive preferential treatment of affiliates.

Q: If we are left with the approach of regulatory rules, incentives, and oversight as the only viable means under the Act of dealing with issues of affiliate relations and market power, what does such an approach entail?

A: The key elements of effective policy are:

- **Functional Separation of Monopoly and Non-Monopoly Activities.** This entails functional isolation of people, information, accounting, cost allocation, and economic decision-making over pricing and marketing. This functional separation permits accurate monitoring of the costs and rates of monopoly services and blocks the transfer of productive information acquired through monopoly service activities to the decision-makers in charge of non-monopoly services. When information is transferred, its existence is appropriately made available to the marketplace competitors of the utility's non-monopoly functions.

- **Unbundled, Non-Discriminatory Access to Monopoly Services.** This entails the provision of all monopoly services, unbundled from non-monopoly services, to third parties on the same terms and conditions as afforded non-monopoly affiliates. It also entails prohibition on "tying", i.e., the conditioning of the purchase of monopoly services on the purchase of non-monopoly services from the utility. Contrary to Prof. Mayo, who confuses tying and bundling by treating them as the same (at 11), this policy prescription does not imply that an affiliate of the EDC should not be allowed to bundle, say, distribution services with electricity supply so long as the former are available to all on an unbundled, nondiscriminatory basis. Under such conditions, there is no compelling policy reason why the affiliate of the EDC should not be able to combine distribution services with supply and offer that package to consumers. The customers will only take the offer if they find it more attractive than the options available from others. Hence, prohibiting such combined service by the utility would leave consumers worse off.[5]

- **No Cross-Subsidization of Non-Monopoly Affiliates by Monopoly Functions.** If a utility could shift costs from non-monopoly functions over to monopoly functions, where higher costs can be recovered in higher regulated monopoly rates, the utility could obviously have some ability to undercut competitors' prices. This, in turn, may hinder competitors' continued participation in the affected marketplace. Cross-subsidization can be thwarted by strict cost allocation rules (as adopted by the Commission and employed by PP&L -- see below). The incentive for engaging in such a practice can also be eliminated by, *for example, a rate cap on monopoly services. This breaks* the link between such services' measured costs and the pass through of costs in rates.

- **Removal of Regulatory and Legal Barriers to Entry into Non-Monopoly Activities.** As I have stressed above, part and

[5] Tying, on the other hand, is the practice by which a company refuses to supply one product or service unless the purchaser buys some related product from that company. In this case, tying would mean that the integrated utilities would refuse to provide non-discriminatory distribution services unless a customer bought electricity supply from it. But this is precisely the practice that the open access, non-discrimination rules will prevent. Dr. Mayo does not point to any flaw in these rules that would somehow permit an EDC such as PP&L to engage in such tying.

parcel of a system of open, non-discriminatory access to a utility's regulated monopoly services is the removal of barriers that would otherwise impede competitors' use of such access. Such *reforms* are under way at the FERC as they affect power pools such as PJM, with a concomitant expansion in power pool membership and participation. At the state level, similar entry-easing policies of licensing and bonding are appropriate.

- **Utility Codes of Conduct with Regulatory Oversight.** It is not practical, nor would it be efficient, for regulators to participate in every decision possibly affecting interaffiliate relationships within an EDC. Accordingly, it is appropriate for regulators to require codes of conduct from incumbent utilities, and to subject adherence to such codes to Commission oversight and enforcement. The content of codes of conduct appropriately includes the protections of functional separation, non-discriminatory access, cost segregation, and the other attributes of interaffiliate relations discussed above. Regulatory oversight, in turn, appropriately takes on the flavor of antitrust enforcement in terms of its concerns over denials of comparable access to essential monopoly services, tying, vertical leveraging and the like.

II.C PP&L's Plan for Restructuring

Q: In your opinion, does the restructuring plan put forward by PP&L in this proceeding satisfy the criteria you have just set out?

A: Yes. PP&L has put forward a plan that contains appropriate functional separation of its monopoly and non-monopoly activities, codes of conduct governing affiliate relations, and incentives for competitive behavior that will protect and promote competition and enable the Company to compete fairly for consumers' business. Such competition will occur, of course, within the regulatory setting and under the oversight of both the Commission and the FERC. Both the Commission and the FERC clearly are focused upon promoting and protecting competition, on removing regulatory and legal barriers to entry, and on the kinds of potentials for anticompetitive abuse that I have discussed here and in my direct testimony. This combination of the Company's restructuring plan and regulatory oversight represents the right step for public policy to take at this time in implementing the Act.

II.C.1 Functional Separation under the Plan

Q: Prof. Kalt, as you see it, what are the salient features of the Company's restructuring plan as they relate to the issues of competition that you have been discussing and that intervenors have raised?

A: Let me first discuss the functional separation of the monopoly and non-monopoly activities of PP&L. As discussed in particular by Mr. Geneczko in his direct and rebuttal testimonies on behalf of PP&L, PP&L is revising its corporate structure and practices in order to achieve a sharp functional separation of its non-monopoly functions and the remaining monopoly activities. Because PP&L intends to try to compete in the restructured retail electricity sector and in the wholesale electricity supply sector, the Company is separating its still-regulated electric delivery activities (including, primarily, transmission and distribution) and its generation supply, acquisition and marketing activities.

Upon the unbundling of its retail rates pursuant to the Act, PP&L's delivery activities will be regulated as monopoly functions. Notably, transmission service to both wholesale and retail customers will be governed by a FERC-approved open access tariff, and distribution service will be similarly governed by PUC open access tariffs. These tariffs are the cornerstone of regulatory policies of non-discriminatory, comparable access, and a primary avenue by which regulatory oversight will act to ensure market access by PP&L's rivals.

The functionally separated portions of PP&L will be housed within two primary divisions of the Company, Generation Supply and Electric Delivery, corresponding to non-monopoly and still-regulated monopoly functions. Separate accounts will apply to the Generation Supply and Electric Delivery groups, with cost allocations between the two governed in accord with the allocation method most recently approved by the Commission. Corporate-level services (e.g., legal services) provided to either Generation Supply of Electric Delivery will be priced to each group according to Commission-approved criteria. As discussed below, relations between the separated Generation Supply and Electric Delivery groups will be governed by the Code of Conduct the Company has developed to comply with FERC Order No. 889 (which requires the functional separation of transmission services from wholesale energy sales services). The Company is extending this Code of Conduct to cover retail transmission service, and an additional Retail Access Code of Conduct is being applied to the separated groups.

Q: Mr. Dirmeier seems to believe that PP&L's functional separation represents only "fictitious boundaries" (at 22). Do you agree with this assessment?

A: No. This assertion by Mr. Dirmeier seems to me to be simply rhetorical, with Mr. Dirmeier presenting functional separation short of divestiture as the essence of "fictitious" (at 22). Mr. Dirmeier appears to have no factual basis for concluding that the specific structural approach put forth by the Company will turn out to be fictitious. In fact, the steps taken by the Company -- separate accounts, regulation-sanctioned cost allocation, FERC and retail-level Codes of Conduct, etc. -- are the proper steps to be taken in a restructured policy environment. Moreover, these steps will be taken under the oversight of the Commission and the FERC. As many gas pipeline companies (including Enron) have learned, "fictitious" functional separation short of divestiture is an invitation to intense scrutiny and regulatory action.

II.C.2 Codes of Conduct

Q: What is your assessment of the adequacy of the codes of conduct being implemented by PP&L?

A: As noted, the Company is implementing the Code of Conduct developed under FERC Order 889 across both wholesale and retail transmission relationships, and its Retail Access Code of Conduct will govern the other dimensions of relationships between its Generation Supply and Electric Delivery groups. Not surprisingly in light of their links back to the FERC's well-tuned attention to the competitive issues raised by affiliate relations in vertically integrated, partially-regulated companies, these Codes of Conduct systematically address each of the areas of potential concern. Specifically, as the Codes are described by Mr. Geneczko, they provide for:[6]

- Open, Non-Discriminatory Access to and Pricing of Regulated Monopoly Services (RMG-2 at 4-5; RMG-3 at 1-2).
- Prohibitions on Conditioning (Tying) of Access to Monopoly Services on Purchase from Generation Supply (RMG-2 at 4-5; RMG-3 at 2).
- Non-Discriminatory Dissemination of Disclosed Market and Competitively Sensitive Information (RMG-2 at 3-5).
- Confidentiality of Customer and Supplier Information (RMG-2 at 4; RMG-3 at 1).
- Segregation of Personnel and Information by Group (RMG-2 at 1; RMG-3 at 1).
- Restriction of Information Transfer Via Personnel Assignment (RMG-2 at 2-3; RMG-3 at 1).
- Separate Cost Allocation, Books, and Records (RMG-2 at 5; RMG-3 at 2).
- Enforcement of Employee Education in the Codes of Conduct (RMG-2 at 5-6; RMG-3 at 2).
- Compliance Reporting, Auditing and Dispute Resolution (RMG-2 at 6; RMG-3 at 2).

Q: Mr. Dirmeier seems to believe that the FERC Code of Conduct and the Retail Access Code of Conduct lack any real force and amount to a

[6] See, also, rebuttal testimony of Mr. Geneczko.

strategy of trying to convince the Commission to just "trust us on this *one" (at 17).*[7] *Do you agree with this assessment?*

A: No. Mr. Dirmeier's recommendation is that PP&L should be subjected at least to "specific rules" or "specific safeguards to preclude prohibited activity" (at 17). While this perspective is in accord with his concern for PP&L's rivals, the development of complex, regulator-intensive and intrusive micro-management rules would be both a source of handicap for PP&L and is unlikely to provide a solution to problems of prohibited activity. If Mr. Dirmeier is right that nothing short of divestiture "could ever control" anticompetitive affiliate dealings (at 21) because the incumbent utilities are able to invent means of circumventing any prohibition, then more and more cumbersome rules should offer no solace to anyone other than rivals with interest in handicapping PP&L.

In fact, it is consistent with sound principles of public policy, which recognize that the enforceability of rules can be inversely proportional to their specificity, that the Codes of Conduct and the regulations that stand behind them (e.g., including open access tariffs and the Act itself) are clear and crisp in their edicts: no discrimination, no cross-subsidization, no tying, no "channeling," no denials of access, no discriminatory transfer of monopoly-acquired information, no joint

[7] Similar assertions are made by Ms. Alexander (at 50-52).

operations, and so on. With these edicts, it is then the proper role of regulatory oversight to require and enforce codes of conduct of precisely the type that PP&L is putting forth.

Q: Mr. Dirmeier argues, however, that companies such as PP&L (and presumably Enron) have "fiduciary responsibilities" to seek out certain activities that are contrary to the intent of rules, regulations, and codes of conduct even when the original intent was to prevent such activities *(at 9). Do you think this supports the contention that PP&L should be* presumed to be able and likely to violate applicable rules, regulations, and/or codes of conduct?

A: No. This perspective does not assist us in devising proper policy under the Act. It might just as well be argued that we all have incentives to rob banks, and to invent devious means for doing so that circumvent the intention of laws against bank robbery. Of course this is true at some metaphysical level, but the essence of a civil society includes the recognition of mutual forbearance, and our legal and moral traditions do not generally support conviction and punishment (handicapping) before the fact of a transgression. We devise rules, guidelines, and codes of conduct, and we develop mechanisms for holding ourselves to them. In the case at hand, the fiduciary responsibility of a company does not extend to breaking the law or violating regulations and regulatory commitments, and the combination of regulatory oversight by the Commission and the FERC and the Company's Codes of Conduct (and related steps, such as functional separation) provide the proper mechanisms for guarding against actions that are inconsistent with securing consumer benefits through promotion of competition in electricity supply markets.

Q: In eschewing micro-management and divestiture approaches that would handicap incumbent utilities and/or proactively support competitors, rather than competition, are regulators such as the FERC and the Commission "going light" on incumbent utilities?

A: This is not an accurate characterization. The goal of sound policy is not to give the incumbent utility the benefit of the doubt or to wait and see if the utility misbehaves. Rather, the proper policy approach recognizes that the utility and its vertical integration have positive efficiencies and benefits to deliver to the marketplace. Policy should be designed to allow those effects to accrue to consumers.

The proper policy approach is anything but "light" on actions by an incumbent utility that utilizes its continuing monopoly status in monopoly functions to thwart competition in unregulated non-monopoly areas. Breaches of codes of conduct and regulations that take the form of extension of a utility's regulated monopoly into otherwise competitive non-monopoly functions are the *sine qua non* of anticompetitive actions. Tying, denials of access, discrimination in the provision of essential regulated monopoly functions -- these actions should be constantly under the oversight of regulators, as well as antitrust authorities. Failure to do so would be to "go light" on integrated utilities in the restructured environment.

II.C.3 Experience in Other Partially-Regulated Industries

Q: Prof. Mayo argues that experience in other partially deregulated industries without divestiture has not gone well. That is, processes of regulatory oversight and enforcement have been unsuccessful in preventing abuses of power by the monopoly arms of integrated companies. Do you agree with this?

A: No. Analogies to other industries are often useful, but they must be drawn carefully and appropriately. I believe that Prof. Mayo has drawn incorrect and inappropriate conclusions from the industry examples he cites.

Consider, for example, Prof. Mayo's suggestion (at 22-23) that the experience with cable television deregulation in 1984 provides evidence that PP&L's approach to restructuring will be inadequate to yield the benefits of competition. Prof. Mayo implies that when cable TV rates were generally deregulated in 1984, there was some kind of open-access competition policy implemented, which then failed to lower rates. In fact, when cable rates were deregulated, Congress took no action to open up cable to competition. Indeed, the vast majority of cable companies continued to hold protected monopoly franchises in their service territories. The "lesson by analogy" of this experience for electricity is that if the Commission were to eliminate price regulation, but continue the monopoly franchise on electricity supply, electricity prices would rise. Since the Commission is maintaining a rate cap and aggressively opening supply to competition, this "lesson" is irrelevant.

Q: Dr. Mayo argues that the experience of telecommunications deregulation demonstrates the unfeasibility of ensuring non-discriminatory open access through regulation. In your opinion, does he draw the appropriate lessons from the telecommunications experience?

A: No. Dr. Mayo's discussion focuses on the break-up of the original AT&T, as this process emerged from and was managed by federal court decisions. Since the Act at issue now in Pennsylvania *specifically prohibits mandatory divestiture, his discussion is somewhat* off the point. Further, despite the use of the divestiture approach to the functional separation of AT&T, Congress last year passed major telecommunications legislation a major thrust of which is to permit, in effect, the re-integration of the telecommunications industry. In so doing the policy decision has been made that the benefits of permitting the regulated local exchange monopolists to compete in the competitive long-distance market, and of permitting the long-distance companies to enter the local exchange markets, are likely to outweigh whatever costs and complexities will be involved in regulating local exchange monopolists so as to ensure non-discriminatory access. The vociferous support for legislation by prospective entrants into local exchange markets, notwithstanding their dependence on local monopolists for access, evidences their expectation that the kind of systems of regulation and oversight that Prof. Mayo (and Mr. Dirmeier) reject can work to promote competition.

In short, despite the decision 15 years ago to break up AT&T, the current direction of U.S. telecommunications policy is toward greater, not lesser, reliance on open-access rules and oversight to permit competition.[8] No one would seriously contend that it does not take effort, intelligence, and resources to devise and implement such rules, but to claim that they have been proven not to work by the

[8] It must be noted that the AT&T case itself is a weak example. First, it was the result of an antitrust case before a federal court that would have been incapable of administering a long-term program of regulatory oversight. Second, the case was settled - AT&T voluntarily decided to exit the local monopoly phone business as part of a strategic decision.

telecommunications experience is incorrect. In fact, it is relevant to point out that, because telephone is a *switched* network,[9] the issues of non-discriminatory access are inherently more complex than in electricity. In other words, policy in telecommunications is moving towards competition in the context of rules-based protections against monopoly abuses, despite an environment in which aspects of the industry make such rules more complex and harder to implement than in electricity.

Q: Do you think that the natural gas deregulation experience provides useful lessons for electricity?

A: Yes, if properly analyzed and applied. A natural gas pipeline bears more similarity to an electricity transmission system than does the phone system. Producers inject gas into the pipeline at various points, and users draw gas off at various points. Just as an electricity user does not care where the electricity she uses "comes from," neither does a gas user care which gas molecules are burned. Moreover, although some pipeline systems are considerably more linear than

[9] That is, the linking of a particular identifiable unit of originating supply (i.e., a phone call) to a specific destination is the essence of the system. In the case of electricity, on the other hand, such physical linking of origin and destination is the rare exception. Rather, all providers feed into the network and all users draw from it, with the mixing of supplies a matter of indifference to ultimate customers.

most electric transmission systems, pipelines face issues of maintaining line pressures at different points that are somewhat analogous to the balancing requirements on an electrical transmission system.

In this environment, the FERC has implemented a policy over the last two decades that has taken the natural gas industry from a position of essentially complete price and entry regulation of all stages, to a system in which the production, aggregation, and marketing of gas have been opened to competition and almost entirely deregulated. Interstate pipelines remain regulated monopolists, somewhat analogous to the regulated wires businesses that will be part of most incumbent EDCs after restructuring. Many pipelines, including important subsidiaries of integrated companies such as Enron, have affiliates that engage in the competitive production, aggregation and marketing of gas over their systems. Under FERC rules, these pipelines are required to provide non-discriminatory access to their systems, and to interact with their competitive affiliates in ways that avoid cross-subsidy and preferential treatment. While no regulatory system is totally free of complaints, this approach has generally worked well and is perceived to have successfully delivered significant *competitive benefits to consumers.*[10]

II.D Incentives and Behavior under the Plan

Q: Prof. Kalt, you mentioned above that incentives embodied in the Act and the Company's proposals, in fact, would work against actions that could thwart the development of competition in electric supply markets. Could you explain?

A: Beyond the oversight and enforcement capacities of the Commission and the FERC as they relate to open access tariffs, anticompetitive behavior, affiliate abuse and the like, there are incentives present in the restructuring plan that directly work against the kinds of extensions of monopoly that intervenors such as Mr. Dirmeier, Mr. Mayo, Mr. Shapiro, Ms. Day and Mr. Johnstone warn of.

Consider, for example, the implications of the Act's rate cap for cross-subsidization of non-monopoly functions. During the period of the rate cap, it would not be profitable for an EDC to shift costs that should be allocated to non-monopoly functions to regulated monopoly functions, since such shifted costs would not be recoverable through a

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[10] For example, The Economic Report to the President, 1996, notes that: "Regulatory reforms in the 1970s and 1980s demonstrated that largely unregulated competition yields more efficient performance in such traditionally regulated industries as air transport and trucking, natural gas production, and long-distance telephone service." (at 159).

rise in regulated rates. Similarly, the regulatory and code of conduct requirements that discretionary offers of monopoly service be made available to all electricity suppliers and customers on common terms and conditions obviates any capacity of an EDC to provide preferential service or pricing in order to promote market dominance by an affiliate. Note, also, that "same terms and conditions" constraints eliminate asserted incentives for "price squeezes" that Prof. Mayo describes as occurring in the presence of (albeit unregulated) vertical market power (at 12).

Q: Mr. Dirmeier is concerned, however, that PP&L is creating incentives and abilities for the Company to lock up customers so that they don't really get the chance to choose suppliers. What assessment do you make of his concerns?

A: Let me first examine Mr. Dirmeier's concerns regarding PP&L's proposed service to customers who "choose not to choose" and who are not yet eligible to choose. The case of the former, in particular, provides further illustration of countervailing incentive effects under PP&L's plan.

Under the Company's plan, customers who "choose not to choose" would be served by PP&L's Electric Delivery group under Rate Schedule RTD. Mr. Dirmeier is concerned that "PP&L is attempting to use its rate schedules to encourage customers not to elect competitive generation supply, in conflict with the goals of the Act" (at 19).[11] Mr. Dirmeier's reasoning, however, is flawed.

First, under the indicated tariff schedule, "choose not to choose" customers would carry no profit potential for the Company: the electricity component of the service would be priced at prevailing market levels, and would be supplied on a direct pass-through (without mark-up) basis. Under these conditions, the opportunity cost of supplying "choose not to choose" customers would be the market price (i.e., the supplier's alternative would be to sell its power into the market at the same price as that charged to "choose not to choose" customers). Thus, there would be no net advantage for the generation supplier to serving the "choose not to choose" sector. Transmission, distribution, and other delivery services would be priced at regulated rates, and PP&L would earn those rates on the customer's service regardless of which supplier provided the electricity. Under such incentives, PP&L's economic interest lies in maximizing throughput on its wires, regardless of who is the seller of the electricity that moves on those wires. Such an interest is the epitome of pro-competitive inducement.

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[11] Notwithstanding these remarks, Mr. Dirmeier then concludes that "choose not to choose" customers should be served by the Electric Delivery group (at 28).

Second, Mr. Dirmeier interprets the economics at issue as: "allowing the Delivery Group to provide de-tariffed generation service to customers who do not exercise choice will provide an incentive...to market or otherwise convince customers not to exercise choice, thereby assuring that PP&L retains the customer's business....[This] is, by definition, anticompetitive" (at 25-6). Professor Mayo fail to understand that no services of the EDC will be de-tariffed. His reasoning, moreover, fails to recognize the point (see above) that, with unbundled transmission, distribution and other delivery services available at regulated rates from PP&L, permitting the Electric Delivery Group to sell both delivery services and electricity is not anticompetitive.[12] Indeed, the sale of bundled electricity and delivery services is likely to be the economic essence of what it would mean for a rival to serve as the agent of customers (as parties such as Enron indicate they desire).

Q: What about customers who are not yet eligible for choice?

A: Mr. Dirmeier also objects to PP&L's treatment of customers not yet eligible for choice. These customers would be served by PP&L's Generation Supply group, receiving bundled service (albeit on

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[12] Indeed, the Electric Delivery Group *must* sell both delivery services and electricity to last resort customers.

unbundled bills) consisting of tariffed transmission, distribution, and other delivery services plus market-priced electricity. Mr. Dirmeier is concerned that it would create a built-in customer base for PP&L yielding "huge" revenues that could be diverted to competitive activities; and create an advantage in soliciting the customers' business at the time of choice (at 26-27).

Economically, Mr. Dirmeier's concern about "huge" revenues from customers not yet eligible for choice is not a concern about cross-subsidization. The complaint is not that PP&L would shift costs into regulated monopoly service tariffs in order to advantage non-monopoly services. Rather, the essence of Mr. Dirmeier's concern is a familiar "big is bad" theme. In particular, the image Mr. Dirmeier constructs is one in which PP&L would have a lot of money, and therefore it would spend that money to undercut the prices of its competitors. This kind of reasoning, in fact, is independent of the source of money to which a company might have access, and Mr. Dirmeier's reasoning would logically imply that he should oppose the market presence of any large firm with lots of money, since any such firm could be presumed to engage in the behavior complained of.[13]

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[13] This reasoning, in fact, is parallel to that of Mr. Biewald, who is concerned that stranded cost recovery by the Company through the CTC will give it a "war chest" by which to predate against competitors (at 20). Mr. Biewald's concern is subject to the same errors as Mr. Dirmeier's.

Tellingly, for the described behavior to be even prospectively profitable on the part of a firm, it must be part of a predatory strategy with a high likelihood of success. An expectation of successful predation *against* sellers of electricity with open access to the generation of numerous, already-built units around the region and with open access to transmission and distribution is wholly inconsistent with sound economic reasoning. Under the conditions at work in the post-restructuring marketplace, no seller of electricity would have a reasonable expectation that it could successfully prey on its rivals with low prices and then subsequently profit by raising prices without attracting yet more rivals into the fray. Mr. Dirmeier's (and Mr. Biewald's raising the prospect of predation is unfounded and without support in fact or theory.

Mr. Dirmeier's other concern (noted above) regarding PP&L's service of "not yet eligible" customers via the Generation Supply group is that the customer contact will give PP&L an advantage when choice is available to such customers.[14] This reasoning, however, is simply illogical. If the "not yet eligible" customers were to be served by PP&L's Electric Delivery group, as Mr. Dirmeier prefers, those customers would be having contact with PP&L anyway. Would Mr.

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[14] See, also, Shapiro at 5.

Dirmeier try to confuse customers by preventing them from becoming aware that a PP&L affiliate would chase their electricity business upon the commencement of choice? Removing information from the market (or introducing misinformation into the market) would not plausibly benefit consumers. The "advantage" Mr. Dirmeier is concerned about derives from the fact that consumers may value PP&L's reputation and may face real costs of pursuing and experimenting with alternatives when choice opens up. As I have discussed at length above, rivals may wish to handicap such advantages, but it is not in the interests of the competitive process or consumers to do so.

Q: Mr. Knecht is concerned that PP&L will lock up "choose not to choose" customers and perhaps other customers of its generation supply by pricing its own generation under market levels. Do you understand his reasoning?

A: Yes. I believe it reflects a straightforward misunderstanding of the Company's plan. In particular, Mr. Knecht seems to be under the impression that PP&L will sell its own generation at less than market levels when, in fact, this is not the case. He writes: "If utility generation service is priced below market rates, PP&L will maintain a dominant market position in its service territory throughout the transition period, by effectively locking in its existing customers at utility generation service rates" (at 8). A similar concern is expressed by Mr. Johnstone (at 7). As discussed above, however, PP&L generation sold to "choose not to choose" customers would be provided at market levels, and "not yet eligible" customers would pay traditional regulated rates.

For both these types of customers as well as customers that choose PP&L, PP&L would not profit from selling below market rates. Doing so would not increase its returns to regulated monopoly services which will be used regardless of whether PP&L is the generation supplier to customers in its service territory. Similarly, PP&L's collection of the CTC is not dependent upon PP&L being the power supplier to such customers.[15] Thus, the effect of selling power below market levels would be to impose the deleterious effect on the Company of foregoing the opportunity to charge what the competitive market will bear for generation. Alternatively stated, selling its power at below market levels would subject PP&L to the opportunity cost of foregoing the ability to sell its power into the market (for distribution in its own territory or elsewhere) at market-based levels or, for "not yet eligible" customers, at traditional regulated rates. Such a strategy would make no sense for the Company to pursue.

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[15] See, also, the rebuttal statement of Dr. Tierney on behalf of PP&L.

Q: Another kind of purported "lock out" that Mr. Dirmeier is concerned about is the prospect that PP&L might sign market-priced electricity supply contracts with certain customers prior to the commencement of competitive access by alternative suppliers (at 44-47). Does this prospect present difficulties inimical to the development of competitive supply markets or promotion of consumers' interests?

A: No. First, it is worth noting that, notwithstanding his assertions of anticompetitive effect, Mr. Dirmeier is aware of no evidence that PP&L is engaged in the long-term contracting that he is challenging.[16] Second, and more fundamentally, long term contracting on a market-priced basis by a utility prior to commencement of a general regime of open access cannot simply be presumed to be anticompetitive. In fact, long term contracting is a mechanism by which customers -- particularly the relatively large and sophisticated kinds of customers commonly seeking long term contracts -- can visit the force of impending competition on a utility's electricity sales even before the commencement of choice. The reason is obvious: the pending opening of choice can enhance the bargaining position of a utility's customers regarding price, length of contract, and other terms and conditions. The presence of choice on the near horizon enables

[16] See, however, rebuttal testimony of Mr. Kasper.

customers to credibly threaten to take only standard tariffed service and/or insist on near-term termination rights that would enable them to depart for other suppliers upon the start of choice.

In short, customers are better off having the option of signing long term purchase contracts with a utility in the face of pending open access than they would be if their only option were to stay with a utility's standard tariffed service and exercise choice upon a future date. It is understandable that rivals would like to expand the number of customers they can chase upon the opening of access, but it is not in customers' interests nor does competition require that customers be required to wait for access in order to realize some of its benefits.

III. STRANDED COST RECOVERY UNDER PP&L'S PLAN

Q: Prof. Kalt, let's turn to issues surrounding the recovery of stranded costs under the Act. Do you believe it is proper that utilities such as PP&L be afforded the reasonable prospect of recovering their stranded costs?

A: Yes. As I discussed at length in my direct testimony, the Pennsylvania public has a clear interest in stability in the "rules of the game" by which those who would invest themselves and their assets in the Pennsylvania economy are bound to play. Instability in the "rules of the game" can raise risk for investors, and thereby raise the cost of capital and discourage investment. This is not to say that changes in the "rules of the game" should not be undertaken when they promise future benefits (such as a more efficient electric power sector); but such changes are not costless if they have negative effects on a jurisdiction's or an industry's investment environment. Sound policy seeks to minimize these costs.

Under the pre-existing rules of the game by which utility investors have made their decisions, such decisions were made with certain expectations -- certainly not without risk -- that followed from the rules of the game. In particular, under pre-restructuring regulatory policy for electric utilities, investors were provided with reasonable prospects of recovering and earning returns on their prudent investments made pursuant to fulfillment of their obligations as franchised monopolies. These prospects followed from the rate making process (with its cognizance of just and reasonable return standards), the process by which investments were permitted into the rate base upon which returns could be earned, and the protection that regulation generally provided from unconstrained competition.

Clearly, restructuring under the Act changes these foundations of investors' risk assessments in fundamental ways. At least with respect to generation-related assets, restructuring promises to eliminate the mechanisms of ratemaking, rate base determination, and insulation from competition that previously characterized the regulatory rules of the game -- or "compact" -- by which risks were structured and within which investments were made.

Billions of dollars are at stake. And no serious observer can fail to recognize that, without some transition mechanism for providing the opportunity to recover costs that investors would otherwise have had a reasonable prospect of recovering, the pending change in the rules of the game would promise to push the price of power down to competitive market levels and leave investors with no recovery of or return on any of the portion of generation costs that are above market levels. Demonstration of a jurisdiction's conscious willingness to change the rules of the game with this resulting impact on investors cannot have any other effect on the investment environment than to worsen it.

III.A Rules of the Game and the Regulatory Compact

Q: Mr. Bradford, testifying on behalf of the Environmentalists, seems to be of the opinion that the deleterious effect on the investment environment that you describe can be avoided, or at least will not be too severe, if investors were aware that something like the foregoing might happen. Is this correct?

A: No, not in the setting we confront in the electric power industry. It is important to recognize that an awareness *ex ante* on the part of investors that open access competition and market-based pricing of generation *might* occur at some uncertain point in the future does not change the fact that the restructuring of the marketplace under the Act has turned a prospect into an actuality. At best, *ex ante* investor anticipations of possible changes in the rules of the game that portend the stranding of above-market generation costs can produce demands for returns that will, if earned over the anticipated life of an investment's payout, offset the *ex ante* expected (probability-weighted) loss of stranded costs.[17] Turning a probability before-the-fact into a certainty after-the-fact still leaves investors with uncompensated losses. In the case at hand, these losses would be extremely large -- as reflected in PP&L's stranded costs (see direct testimony of Mr. Krall on behalf of PP&L).

Q: But Mr. Bradford concludes that: "There never was...a regulatory compact." Do you agree?

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[17] For this reason, the kinds of forewarnings of change provided by financial pundits, politicians, professors, business executives, and others of the type cited anecdotally by Mr. Bradford do not suffice at all to demonstrate that investors had certain knowledge of regulatory change at a certain date.

A: No. I believe there has been a regulatory compact in precisely the way I have describe above and in my direct testimony: there has been a set of rules of the game by which utilities in Pennsylvania and investments in those utilities have been regulated. Those rules had relative stability and certainly were not seen as carrying the certainty of their abandonment at the time relevant investment decisions now embedded in generation assets were made.

As I understand Mr. Bradford, he defines the *existence* of a regulatory compact in primarily legal terms, and searches for an enforceable contract or compact by which investors' rights to partial or full recovery of stranded costs could be upheld. He concludes that no such enforceable agreement exists, or at least none exists that investors could be certain would be enforced by the highest courts. As a non-lawyer, I cannot opine as to whether Mr. Bradford's legal analyses and forecasts are right. But should we conclude that it would, therefore, be unfair or poor public policy to permit investors the opportunity to recover stranded costs because investors should not have relied on an unenforceable contract or compact? Or that stranded cost recovery should be blocked because investors should have at least seen that enforceability of the regulatory compact was not certain?

Whether or not stranded cost recovery would be upheld in a particular court (say, by the U.S. Supreme Court on a "takings" claim or some other grounds) is largely beside the point when it comes to the economic and public policy implications of stranded cost recovery. For it seems to be beyond reason to hold that: 1) utility investors did not rely on the prior rules of the regulatory game in forming their expectations about risks and returns, and 2) that the restructuring underway in Pennsylvania does not represent dramatic and discontinuous change in the regulatory rules of the game. Indeed, if there were no prior rules of the game by which parties played -- no regulatory compact to be changed -- what was the Pennsylvania legislature doing by the Act and why has the legislature's Act led to such intensive, expensive, and far-reaching proceedings such as the one we are engaged in here? The pending change in the regulatory rules of the game is obviously dramatic, but it could not be so without the existence of a prior set of rules to move away from -- i.e., the regulatory compact of more traditional monopoly regulation.

Q: *Mr. Bradford argues that, even if there were a regulatory compact at some earlier date, it has long since been broken to the point that it would not have been relied upon by rational investors. Is this a correct argument in your view?*

A: No. As is implicit from the discussion above, the economic essence of *breaking* the compact of more traditional monopoly regulation is the actuality of policy change -- taking one of many possible future directions of policy (such as competitive access) and turning it into a certainty. Thus, while there is no doubt that competitive access is one possible direction of policy that investors in today's generation assets may have been able to take into account *ex ante*, implementation of the Act in question here clearly turns possibility into fact.

To be sure, various aspects of traditional regulation of monopoly franchises have changed over recent years, including the treatment of cost overruns, conservation (DSM) expenditures, and the like; however, the stark step of terminating the effective exclusivity of most utilities' retail service territories is the change that presents itself now. The suspension of this "rule of the game" was not a certainty at the time the investments that have built the present stock of generation capital were being made.

This distinction between various components of the regulatory compact of varying degrees of importance is apparently not understood by Mr. Bradford. He cites, for example, prior research of my own regarding the willingness of state public utility commissions to permit the rate basing of putatively prudent cost overruns, particularly the very large overruns that many utilities experienced as they brought nuclear plants on line in the early and mid-1980s (at 15).[18] My research indicated that many jurisdictions at this time resisted the rate basing of expensive generation plant, particularly plant that came in far over original cost estimates. In certain jurisdictions, this resistance took the form of after-the-fact *de jure* and *de facto* changes in the regulatory standards of "prudence," "used and useful," and related concepts by which commissions determined whether an investment would be recoverable in rates. In some cases, this, indeed, constituted a breach of the pre-existing regulatory bargain.

None of this means, however, as Mr. Bradford tries to suggest, that the regulatory rules of the game -- the regulatory compact -- governing the closing of traditional utilities' systems to access by competitors was breached or seen by investors to be a certain foregone conclusion as of the mid-1980s.[19] We are right now in the

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[18] Kalt, J.P., H. Lee, H. Leonard, *Re-establishing the Regulatory Bargain in the Electric Utility Industry*, Energy and Environmental Policy Center, Harvard University, March 1987. Mr. Bradford selectively cites my work. The complete passage reads: "From the perspective of the utility companies, the Massachusetts decision appeared to penalize investors for unavoidable errors in projecting demand, in order to keep rates from piercing some perceived ceiling of political acceptability. Further, by changing the rules in mid-stream, the DPU had raised the possibility that future regulatory commissions would do the same. Finally, the requirement that future investments meet a market test introduced what the utilities considered a no-win proposition. If they misjudge demand they will lose; but if they make good investments, future regulators will allow them to do no more than break even. Thus, companies on average will face losses on their investments. This perceived asymmetry in financial returns is at the heart of the breakdown in the regulatory bargain" (at 2). The report then goes on to describe the consequences of violating this regulatory bargain, including increasing the cost of capital of firms.

[19] It also certainly does not mean that I concluded that the rules of the game embodied in the Act were a certain foregone conclusion as of the mid-1980s -- as Mr. Bradford's assertions

beginning of the era of open access. While Pennsylvania is one of the leaders in this change in policy, it cannot be said that open access of retail franchises is the norm in the United States. Finally, if and to the extent that investors have had the expectation that open access would come to Pennsylvania and other jurisdictions, they would also have the reasonable expectation that open access would not necessarily mean the loss of stranded costs. Their investment decisions would rationally reflect such a prospect.

III.B Criteria of Stranded Cost Recovery

Q: Mr. Baron, testifying on behalf of the PP&L Industrial Customer Alliance, argues that the recovery of stranded costs should be limited or rejected on the grounds that they are "costs that are no longer used and useful (from an economic perspective) in a competitive environment" (at 16). Mr. Bradford takes a somewhat similar position (at 13). What is your assessment of this argument?

A: Mr. Baron makes this argument as a legal assertion, focusing on the precedence of used and useful criteria in the Pennsylvania

might imply. In fact, his assertion that my prior research concluded that investors in used and useful states had no assurance that prudent investment would be recovered misrepresents the research findings. I found that "...in practice, used-and-useful criteria are often modified by prudence considerations, leading to the delayed or partial recovery of excess capacity or abandoned plant costs" (Kalt, J.P., H. Lee, H. Leonard, *op. cit.* at 88); and this conclusion held for Pennsylvania (at Table 2).

Commission's treatment of cost recovery. From a public policy perspective the argument is flawed. It is obvious that what makes certain assets "unused and unuseful" in Baron's sense of uneconomic in a competitive environment is the conscious and explicit decision of policymakers to introduce such an environment. Absent this decision (i.e., with continued protection of incumbent utilities from competitive access by rivals), the assets would be used and useful as such an environment of protection can generally support prices that would make the capacity in question economic. Mr. Baron's position, thus, amounts to the conclusion that the ability of policymakers to determine the economic viability of a utility's assets should be determinative of the question of recovery of the costs of such assets. Such a policy implies an environment that subjects investors to extreme political risk.

III.C Rate Design for Stranded Cost Recovery

Q: Prof. Kalt, you mentioned above that sound policy seeks to minimize the costs in terms of effects on the investment environment that can be created by denying investors the reasonable opportunity to recover their stranded costs. Could you please explain what you mean?

A: As I discussed in my direct testimony, it is consistent with sound policy to provide investors the opportunity to recover the costs of otherwise proper investments made pursuant to their fulfillment of the regulatory regime in place at the time of their cost-creating decisions. In order to implement such an approach to stranded costs at the same time as policy is being reformed to permit access to utilities' systems by rivals, stranded cost recovery should be achieved through non-bypassable charges paid by all parties utilizing the utility's monopoly services. Finally, such charges are appropriately loaded into fixed (non-volumetric or non-usage related) customer charges to the extent consistent with other goals of rate design. This ensures that volumetric rates at the margin for delivered electricity are minimally distorted relative to marginal costs, thus sending less distorted price signals for volumetric decisions by customers.

This description of the economically appropriate design of stranded cost recovery comports with the Act and the Company's plan. Specifically, stranded costs (together with other non-supply, non-marginal costs, such as social policy costs) would be recovered by the CTC. As described in detail by Dr. Tierney in her direct and rebuttal statements, the rate designs put forth by the Company would place substantial portions of the CTC into fixed charges, unloading costs that otherwise underlie usage charges.

Q: Mr. Schoengold (on behalf of the Environmentalists) seems to understand the Company to be calling for 100% recovery of stranded costs (at 18). Is this your position?

A: No. As I have said, policy should permit utilities the reasonable opportunity to recover their investment costs arising pursuant to their fulfillment of their obligations under the regulatory regime in place at the time they made the relevant decisions. In fact, the Company's plan does not call for 100% recovery of stranded costs. As discussed by Mr. Krall in his direct testimony (at 10), the plan shows the Company recovering approximately $600 million less than its $4.6 billion in stranded costs.

Moreover, this level of recovery is not guaranteed. As described in the rebuttal statement of Dr. Tierney, PP&L is subject to asymmetric risks with respect to stranded cost recovery. If market prices of power turn out to be higher than projected in the plan, the Company's recovery of stranded costs will be reduced. If market prices turn out to be generally lower than the plan projects, such lower prices will be passed through to consumers, leaving stranded cost recovery (and the CTC) unchanged.

Q: A number of intervenors argue for further restrictions on the amount of PP&L's stranded cost recovery. Do you find their arguments in this regard convincing?

A: No. In the case of Mr. Baron, for example, he asserts that shareholders should give up earning any further return on investment dollars that are now strandable. Beyond the flawed appeal to the ability of the regulator to designate stranded assets tautologically as "unused and unuseful" by implementing open access reforms (see above), Baron offers no justification for his criterion of disallowance. Moreover, Mr. Baron applies his "unused and unuseful" only to stranded utility generation assets, but not to other stranded assets such as non-utility (NUG) power contracts. The distinction is arbitrary from a public policy perspective.

Similarly, Mr. Schoengold would limit stranded cost recovery -- to 42.7% of their full value. This figure "will provide enough revenue to fully pay off the debt holders without decreasing the return the stockholders have already earned," according to Mr. Schoengold (at 3). And Mr. Schoengold declares this level of recovery to be "reasonable" (at 3), asserting that "a sharing of the economic loss is appropriate" (at 19). This, however, begs the question: why would it be appropriate for shareholders to bear the loss that Mr. Schoengold calculates (i.e., 57.3% = 100% - 42.7%) of the stranded costs? No principles are offered in defense of this position.

Q: What principles can guide the determination of the level of allowed stranded cost recovery?

A: From a strictly economic point of view, I have already expressed the opinion that proper policy should provide investors with the reasonable prospect of recovering that level of stranded costs that utilities incurred pursuant to their obligations under the regulatory system in place at the time of their key cost-creating decisions. This prescription amounts to holding the policy process to the regulatory rules of the game at the time of relevant investments. It provides for minimization of the avoidable risks of policy instability: if policy changes, the investor's prospects of recovering pre-change costs will not be thereby altered.

I recognize, of course, that the present debates over stranded cost recovery in numerous states involve consideration of factors beyond the purely economic. Such factors include political feasibility and concern for rate relief and/or stability, as well as issues of interclass and intraclass (of customer) equity and the speed of recovery.

In the case at hand, the Pennsylvania legislature (with concurrence by the Governor) has addressed the issue of stranded cost recovery with the Act. In so doing, a framework has been provided *which* should properly be taken to represent expressions of the legislature's resolution and balancing of policy objectives. The Company's plan accords with the Act by abiding by its rate caps and determining the CTC as the residual between capped rates and the sum of market-priced power and regulated transmission and distribution (including other delivery services) rates. This respects the goal of rate stability and the permissibility of stranded cost recovery, while implicitly deciding matters of "sharing" by leaving the CTC (and, hence, stranded cost recovery) to be determined as the outcome of a balance between the goals of rate stability and the goals of selling market-priced power over regulated transmission and distribution lines.

Q: As you have noted, in implementing a CTC for recovery of stranded costs, PP&L proposes to put substantial portions of the CTC into *fixed* charges (either on an optional basis in the case of residential customers, or for all customers in the case of commercial and industrial users). Some intervenors question this approach. Is it proper?

A: Yes. As I have discussed, the costs represented by the CTC are not *incremental going-forward costs of meeting customers' demands*. Rather, they arise from fixed and sunk decisions related (primarily) to past efforts of PP&L to secure sources of power. Accordingly, it is consistent with improved efficiency in electricity supply to move CTC charges toward non-marginal charges unrelated to usage.

Mr. Baron objects that the resulting rate designs which put 50% of the CTC into fixed charges amounts to a take-or-pay charge that shifts risks of sales volatility to the customer and away from PP&L (at 42). Similar concerns are contained in Mr. Knecht's worries about the impact of the CTC structure on businesses experiencing substantial declines in power needs (at 38-39). As discussed in Dr. Tierney's rebuttal testimony, however, the CTC design is consistent with the Act's admonition that CTC charges be non-bypassable. Usage-based CTC charges are avoidable to the extent that usage is reduced, and price-sensitive customers would be particularly able to avoid the CTC were it entirely loaded into usage charges. As discussed by Dr. Tierney, the design of the CTC component of rates also reflects the balancing of risks of CTC collection and the goals of revenue stability.

Q: The Environmentalists generally recommend putting the CTC entirely into usage-related charges (Biewald at 8,40; Schoengold at 27-28; Bradford at 28). What is their reasoning?

A: The witnesses for the Environmentalists urge usage-based CTC charges in order to increase the marginal price of delivered electricity seen by the consumer. The goal is to show the consumer higher marginal (usage-related) prices in order to maximally discourage electricity use and, thereby, environmental pollution associated with the generation, transmission, and distribution of electric power.

Q: Is this an appropriate use of CTC charges?

A: Certainly pollution of the environment should be a matter of public policy concern. But principles of policy design argue against the use of the CTC as the policy tool for addressing concerns about pollution. In light of the interests they represent, it is understandable that the Environmentalists would seek to utilize the reform of the economics of the electric power sector to pursue their environmental policy goals. The difficulty, however, is that bringing such policy objectives in through this venue does not permit rational consideration of all dimensions of the problem.

Consider, for example, the implicit proposal of the Environmentalists to design usage-based CTC charges in order to discourage electricity use. While it is straightforward to point out that electricity use can lead to pollution, the Environmentalists' proposal fails to address the presence of other policies -- from tradable permits in sulfur to appliance efficiency measures -- about which a societal decision has already been made as to the appropriate level of regulatory intervention. Making environmental policy through the vehicle of electricity policy can contravene such societal decisions.

The implied policy prescription is to get electricity prices and practices in order and separately get environmental policy in order. It could turn out that a proper and societally acceptable component of the latter is taxes on the usage of electricity. If so, getting electricity pricing "right" would not preclude imposition of such taxes. But it could also turn out that full consideration of taxes and other approaches to controlling electricity-related pollution favors other approaches. In that case, we would have erred in adopting the recommendation in this electric industry restructuring proceeding of pushing all CTC charges into volumetric rates.

Q: Does this complete your testimony?
A: Yes, it does.

EXHIBIT JPK 1

Exhibit JPK 1

Atlantic Electric
AIG Trading Corporation
American Energy Solutions, Inc.
Aquila Power Corporation
AYP Energy, Inc.
Baltimore Gas and Electric Company
Camden Cogen, L.P.
Cinergy Services, Inc.
Citizens Power Sales
ConAgra Energy Service, Inc.
Consolidated Edison Company of NY Inc.
Constellation Power Source, Inc.
Delmarva Power and Light Company
Detroit Edison Company
Duke Energy Power Services, Inc.
Duke Energy Trading and Marketing, L.L.C.
DuPont Power Marketing, Inc.
Easton Utilities Commission
Electric Clearinghouse, Inc.
Enron Power Marketing, Inc.
Energy Power Marketing Corp.
Fina Energy Services Company
GPU Energy
Koch Energy Trading, Inc.
LG&E Power Marketing, Inc.
Morgan Stanley Capital Group, Inc.
New England Power Company
Niagara Mohawk Power Corporation
NorAm Energy Services, Inc.
North American Energy Conservation, Inc.
Northeast Utilities Service Company
PacifiCorp Power Marketing, Inc
PECO Energy Company
Pennsylvania Power & Light Company
Plum Street Energy Marketing, Inc.
Potomac Electric Power Company
ProMark Energy, Inc.
Public Service Electric and Gas Company
Schuylkill Energy Resources, Inc.
Sonat Power Marketing L.P.
Southern Energy Trading and Marketing, Inc.
Strategic Energy Ltd.
UGI Utilities, Inc. - Electric Division
USGen Power Services, L.P.
Virginia Power Company
Virol Gas and Electric, L.L.C.
Williams Energy Services Company

BEFORE THE

PENNSYLVANIA *PUBLIC UTILITY COMMISSION*

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 2-R

Rebuttal Testimony of Ronald E. Hill

Q. *Please state your full name and business address.*
A. Ronald E. Hill, Two North Ninth Street, Allentown, Pennsylvania 18101.

Q. By whom are you employed and in what capacity?
A. I am employed by Pennsylvania Power & Light Company (PP&L or the Company) as Senior Vice President - Financial.

Q. Have you previously submitted direct testimony on behalf of PP&L in this proceeding?
A. Yes. I submitted direct testimony (Statement No. 2) on April 1, 1997.

Q. What is the purpose of your rebuttal testimony?
A. My rebuttal testimony will provide a broad overall policy perspective on this case and will identify several proposals that are inappropriate from that perspective. A detailed analysis of and response to specific proposals submitted by the intervenors will be provided by other PP&L rebuttal witnesses.

Q. Specifically, what issues will you address in your rebuttal testimony?
A. I will address three issues. First, I will discuss what I believe are groundless assertions regarding PP&L's conduct, and improper

constraints on PP&L's ability to participate in the competitive generation market that have been proposed by Enron Power Marketing, Inc. (Enron) and other parties. Second, I will discuss the shockingly inadequate stranded cost recommendations that have been developed by the Office of Consumer Advocate (OCA) and the PP&L Industrial Customer Alliance (PPLICA). Third, I will discuss proposals for unfair sharing of stranded costs submitted by the Commission's Office of Trial Staff (OTS) and PPLICA.

Q. Dr. Mayo and Mr. Dirmeier of Enron discuss a number of ways in which PP&L could circumvent provisions of the Electricity Generation Customer Choice and Competition Act (Act) and PP&L's Code of Conduct to frustrate the introduction of competition in Pennsylvania. What is the Company's position regarding these assertions?

A. I am particularly concerned about Dr. Mayo's and Mr. Dirmeier's suggestions that PP&L will be working to undermine retail competition. PP&L has a deep and strong tradition of operating its business in a lawful and ethical manner. We follow not only the letter of the law and regulations but the spirit as well. PP&L does not spend its time looking for ways to disadvantage competitors so as to prevent customers from obtaining the benefits of full and open competition. PP&L made an early commitment to competition and we intend to work hard to see it be a success.

Q. Is there a specific restriction you would like to address?

A. Yes. I particularly believe that the proposed restrictions on the use of the PP&L name are unfair and inappropriate. The Company's share-owners, directors, officers and employees have worked hard over the last 75 years to provide safe, reliable electric service at fair and reasonable rates. We have done far more than minimally necessary to meet our obligations under the Public Utility Code and Commission regulations. I think our efforts have been successful. We are proud of PP&L's excellent reputation throughout its service territory and be-yond. It is only fair that, as the Company's enters into a new com-petitive era, it should be permitted to rely upon that reputation as it seeks to enter new markets for electric energy.

Q. Turning to the second issue, what is your concern regarding the stranded cost recommendations by the OCA and PPLICA?

A. As I discussed in my direct testimony, PP&L has determined that it has a total net stranded cost liability of approximately $4.6 billion (after $1.0 billion in mitigation), but can recover only $4.0 billion under the rate cap imposed by the Act. Most of the intervenors in this proceeding did not present any analysis of the Company's stranded cost claim. Several other parties, including OTS, the American Association of Retired Persons (AARP), the Office of Small Business Advocate (OSBA), the OCA and PPLICA, presented testimony on this issue. Two of these intervenors reached shocking conclusions. The OCA estimated that PP&L's stranded costs totaled only $383 million and PPLICA developed an estimate of only $661 million.

Q. Why do you characterize these proposals as shocking?

A. I use this characterization for two reasons. First, and foremost, I do not believe that the OCA and PPLICA stranded cost recommendations are the type of result intended by the Act. In my opinion, the Act contemplated a fair balancing of costs and benefits among all stakeholders as Pennsylvania moves toward a competitive electric generation market. The recommendations developed by the OCA and PPLICA simply do not reflect such a balancing. Second, these proposals do not satisfy the "just and reasonable" standard set forth in the Act because, if adopted by the Commission, these proposals would have a devastating impact upon PP&L's financial health.

PP&L witness Joseph R. Schadt prepared a detailed analysis of the impact of the OCA proposal on PP&L. And, because the magnitude of the PPLICA recommendation is very similar to the OCA recommendation, I believe Mr. Schadt's analysis also applies to the PPLICA proposal. In summary, if these recommendations are accepted by the Commission, the Company's financial integrity would be destroyed. The generation portion of the business probably would fail and the ability of the transmission and distribution portion of the business to maintain financial stability would be endangered. If adopted by the Commission, these proposals could compromise the Company's ability to meet its responsibilities as supplier of last resort, to obtain credit, to maintain adequate system reliability and to do so in an acceptably safe manner. In short, these recommendations are a formula for the Company's financial disaster and, accordingly, should be rejected.

Q. Turning to the third issue, what proposals for sharing of stranded costs have been submitted in this proceeding?

A. Both the OTS and PPLICA propose that the Company's shareowners absorb a portion of the Company's stranded costs associated with its investment in generating plants. The OTS proposes to accomplish this sharing by simply assigning 10 percent of these stranded costs to shareowners. PPLICA proposes to accomplish this sharing by dis-allowing an equity return in the Company's investment in generating facilities.

Q. What is your reactions to these proposals?

A. I believe they are totally inappropriate. The Company's claim for recovery of stranded costs in this proceeding is just and reasonable and is fully consistent with all provisions of the Act. Specifically, the Company's claim already reflects more than $1.0 billion in stranded cost mitigation including mitigation efforts planned for the future. The Company and its shareowners will bear the risk if these future mitigation objectives cannot be achieved. Moreover, the Company's filing already reflects a significant reduction in stranded costs that can be recovered by the Company. As I testified previously, PP&L has demonstrated that it has approximately $4.6 billion in stranded costs, but under the rate cap imposed by the Act is claiming recovery of only $4.0 billion.

Q. Could shareowners incur additional stranded cost burdens under the Act?

A. Yes. The Act caps total utility rates at the level in effect on January 1, 1997. As a part of this Restructuring Plan, the Company is proposing to unbundle total rates into individual components -- transmission, distribution, generation and Competitive Transition Charge (CTC). If, during the time period that the rate cap is in effect, generation costs increase above the level in effect on January 1, 1997, the Company will have to provide a credit to customers so that total rate levels do not violate the rate cap. The result would be a reduced level of stranded cost recovery, to the ultimate detriment of the utility's shareowners. Any additional disallowance, in the guise of a sharing arrangement, would be totally inappropriate.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 3-R

Rebuttal Testimony of Joseph M. Kleha

Q. Please state your full name and business address.

A. My name is Joseph M. Kleha. My business address is Two North Ninth Street, Allentown, Pennsylvania, 18101.

Q. Have you previously submitted direct testimony in this proceeding on behalf of Pennsylvania Power & Light Company?

A. Yes. I submitted my direct testimony (Statement No. 3) on April 1, 1997.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the assertions of witnesses on behalf of various intervenors on the following topics:

1. The appropriate methodology for calculating PP&L's stranded costs under the provisions of the Electricity Generation Customer Choice and Competition Act (Act) (responding to Messrs. La Capra, Baron and Falkenberg);
2. The appropriate allocation ratios to be used in determining the PUC-jurisdictional portion of PP&L's overall level of stranded costs (responding to Messrs. La Capra and Schoengold);

3. The appropriate cost allocation study and functional unbundling analysis to be used for PP&L's Restructuring Plan filing (responding to Messrs. Reising and Baron);

4. The appropriate amount of unrecovered energy costs to be included as stranded costs (responding to Messrs. Kollen, La Capra and Catlin);

5. The appropriate competitive transition charge (CTC) reconciliation calculation and process (responding to Messrs. Boonin and Baron);

6. The appropriate allocation of the CTC to rate classes (responding to Mr. Schoengold);

7. The appropriateness of a "delivery" charge recovery of nuclear decommissioning costs (responding to Messrs. Kollen and Biewald);

8. The appropriate allocation of nuclear decommissioning costs to rate classes for CTC recovery (responding to Mr. Baron);

9. The appropriateness of stranded cost recovery of fossil decommissioning costs (responding to Messrs. Kollen, La Capra, Catlin and Gruber);

10. The appropriate allocation of universal service program costs to rate classes (responding to Mr. Reed and Ms. Brockway); and

11. The appropriate cost recovery mechanism for generation service-related costs (responding to Messrs. Johnstone and Schoengold).

Methodology for Stranded Cost Calculation

Q. Have you reviewed Mr. La Capra's testimony regarding his proposed methodology for determining stranded costs in this proceeding?

A. Yes.

Q. What methodology does Mr. La Capra propose to use?

A. Mr. La Capra proposes a methodology that calculates stranded costs as "the difference between the net book value of the generation-related assets as of January 1, 1999 and the estimated market value of those assets as of that date." In addition, Mr. La Capra's testimony implies that the "revenue requirements or regulatory" methodology overstates PP&L's estimate of its stranded costs.

Q. Do you agree with the use of Mr. La Capra's proposed methodology?

A. No. I do not.

Q. Please explain.

A. Mr. La Capra's proposed methodology is inconsistent with the definition of "transition or stranded costs" contained in Section 2803 of the Act. That section defines stranded costs in Pennsylvania as follows:

> 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.

I believe that the Act, as evidenced by this definition of stranded costs, contemplates that a utility's estimate of those costs should be calculated on the basis of the widely-accepted revenue requirements or regulatory methodology.

Q. Do you agree with Mr. La Capra's implication that the revenue requirements methodology overstates PP&L's estimate of its stranded costs?

A. No, I do not. Mr. La Capra's implication that the revenue requirements methodology overstates PP&L's estimate of its stranded costs is simply wrong.

Q. How did PP&L calculate its estimate of stranded costs?

A. As Mr. La Capra acknowledges in his direct testimony (page 13), PP&L calculated its estimate of stranded costs by using the revenue requirements methodology to determine the estimated revenue stream from its generation-related assets and liabilities that would be recoverable under traditional regulation over the life of those assets and liabilities. The annual level of that revenue stream was compared to the annual market price for generation in a competitive marketplace. The net present value of the sum of those differences is the overall level of PP&L's stranded costs.

Q. Please describe the revenue requirements methodology.

A. Under traditional regulation, the basic objective of utility ratemaking is to identify a utility's revenue requirements. That is, the amount of revenue a utility must recover to (1) meet its obligation to provide reliable service to customers and (2) permit its investors the opportunity to earn a reasonable return on their investment.

A utility's revenue requirements are determined by calculating the overall amount of capital costs (a return on and a return of its investment in facilities and other property devoted to public utility service) and operating expenses (fuel, purchased power and other

O&M costs; taxes (state and federal); and depreciation). This overall level of a utility's revenue requirements forms the basis for rates charged to customers.

Q. What is your conclusion regarding Mr. La Capra's proposed methodology for estimating PP&L's overall level of stranded costs?

A. Mr. La Capra's proposed methodology for estimating PP&L's overall level of stranded costs should be rejected for two reasons. First, it is inconsistent with the express language and the intent of the Act. Second, it fails to calculate accurately the overall level of PP&L's known and measurable generation-related stranded costs that would be recoverable under traditional regulation over the life of the assets or liabilities which give rise to those stranded costs, as required by the Act.

Q. Mr. Kleha, is the revenue requirements methodology used to establish customer rates under traditional regulation?

A. Yes. In my 20 years of experience with the ratemaking practices of this Commission (and other regulatory commissions), I have observed that it consistently has established retail customer rates by use of the revenue requirements methodology. As such, those rates reflect prudently-incurred generation-related capital and operating costs which are recoverable under traditional regulation, but which, by virtue of the Act, now may not be recoverable in a competitive electric generation market. That is, generation-related stranded costs, as defined by the Act, already are included in retail customer rates developed, reviewed, approved and applied under the revenue requirements methodology. Moreover, PP&L's existing retail customer rates which, pursuant to the Act and the Commission's restructuring plan filing guidelines, are the starting point for functionally unbundled charges to customers under competition and the Company's calculation of stranded costs, were established by use of the traditional revenue requirements methodology.

Q. Do your comments also apply to Messrs. Baron's and Falkenberg's proposed calculation of the overall level of PP&L's stranded costs using a similar methodology to that used by Mr. La Capra?

A. Yes, they do.

PUC-Jurisdictional Allocation Ratios

Q. Mr. Kleha, have you reviewed the testimony of Messrs. La Capra and Schoengold regarding the allocation ratios to be used to determine the PUC-jurisdictional portion of PP&L's overall level of stranded costs?

A. Yes, I have.

Q. Do you agree with the proposals of Messrs. La Capra and Schoengold.

A. No, I do not.

Q. Please explain.

A. Mr. La Capra proposes to use the allocation ratios contained in Exhibit JMK 1 to determine the PUC-jurisdictional portion of PP&L's overall level of stranded costs. The PUC-jurisdictional allocation ratios contained in Exhibit JMK 1 are based on data for the test year ended September 30, 1995 which was used in the Company's most recent base rate proceeding at Docket No. R-00943271. Although these allocation ratios are an appropriate starting point, these ratios must be adjusted for known and measurable changes, which would be recognized under traditional regulation, to be consistent with the intent of the Act and its contemplated use of the traditional revenue requirements methodology to make a proper calculation of the PUC - jurisdictional portion of PP&L's overall level of stranded costs.

Q. What allocation ratios did PP&L use to calculate the PUC-jurisdictional portion of its overall level of stranded costs?

A. Exhibit JRS 1, which provides the derivation of PP&L's overall level of stranded costs, reflects PUC-jurisdictional allocation ratios derived from Exhibit JMK 1. The applicable ratios shown in Exhibit JMK 1 were adjusted for known and measurable changes to the Company's existing wholesale bulk power contracts, the contract with UGI Utilities, Inc. - Electric Division (a partial requirements wholesale customer), and PP&L's full requirements wholesale municipal customers, including Citizens' Electric Company and Allegheny Electric Cooperative, Inc. These changes include expiration of the existing bulk power contracts as follows:

- Jersey Central Power & Light Company (JCP&L) -- ratably over a 5-year period ending December 31, 1999;
- Atlantic City Electric Company (ACE) -- March 20, 1998; and
- Baltimore Gas and Electric Company (BG&E) -- May 31, 2001.

Q. Should the capital and operating costs associated with these expiring bulk power contracts be included in the calculation of PP&L's overall level of stranded costs?

A. Absolutely. Under the Act, the determination of a utility's overall level of stranded costs is made by calculating the applicable revenue requirements over the term/life of its generation-related assets or liabilities and comparing the annual level of that revenue stream to the annual competitive market price for electricity generation. PP&L's stranded cost claim properly reflects the applicable PUC-jurisdictional revenue requirements associated with all of its generation-related capital and operating costs recoverable from requirements service customers under traditional regulation, including those costs previously associated with expiring wholesale bulk power contracts.

Q. What is your conclusion regarding Mr. La Capra's proposed use of 1995 PUC-jurisdictional allocation ratios?

A. Based on the foregoing discussion, Mr. La Capra's proposed use of 1995 allocation ratios to calculate the PUC-jurisdictional portion of PP&L's overall level of stranded costs is inappropriate, inconsistent with the intent of the Act, and should be rejected.

Q. What has Mr. Schoengold proposed regarding PUC-jurisdictional allocation ratios?

A. Mr. Schoengold proposes to use a single, static allocation ratio of 80% to determine the PUC-jurisdictional portion of each component of PP&L's stranded cost estimate.

Q. Do you agree with Mr. Schoengold's proposal?

A. No. For all of the reasons I previously identified regarding Mr. La Capra's proposed PUC-jurisdictional allocation ratios, Mr. Schoengold's single, static allocation ratio also should be rejected.

<u>Cost Allocation Study and Functional Unbundling Analysis</u>

Q. Have you reviewed Mr. Reising's testimony regarding the appropriate cost allocation study and functional unbundling analysis to be used in this proceeding?

A. Yes, I have. Mr. Reising asserts that PP&L's cost allocation study and functional unbundling analysis are not consistent with the Act and the Commission's final guidelines, are based on "stale" data, and are internally inconsistent.

Q. Do you agree with Mr. Reising's comments?

A. No, I do not.

Q. Please explain.

A. As Section 2804 of the Act clearly indicates, electric utilities are required only to unbundle their present cost structure into the generation, transmission and distribution functional categories. It does not require electric utilities to unbundle their cost structure beyond these three categories. Moreover, the PUC has not directed jurisdictional electric utilities to unbundle their costs beyond these functional categories. PP&L's functional unbundling analysis, Exhibit JMK 2, uses the data shown in PP&L's cost allocation study, Exhibit JMK 1, to provide a detailed separation of the Company's present cost structure into those functional categories required by the Act and the Commission's restructuring plan filing guidelines. Therefore, contrary to Mr. Reising's assertion, PP&L's cost allocation study and functional unbundling analysis submitted in this proceeding are fully consistent with the language and the intent of the Act and the Commission's restructuring plan filing guidelines.

The text of the Commission's restructuring plan filing guideline RP-I.1. indicates that the cost allocation study selected by the filing utility must be consistent with the cost allocation study used in that utility's most recent base rate proceeding. PP&L's cost allocation study, Exhibit JMK 1, represents compliance with the results of the Commission's Final Order in the Company's most recent base rate proceeding at Docket No. R-00943271. The revenue requirements data contained in that exhibit forms the basis for existing retail customer tariff rates. PP&L's functional unbundling analysis, Exhibit JMK 2, provides the results of the unbundling of the data contained in Exhibit JMK 1 into the functional categories of generation, transmission and distribution, as required by the Act and the Commission's restructuring plan filing guidelines. Because these exhibits are based on data from the Company's most recent base rate proceeding which forms the basis for existing customer rates, which were capped as of January 1, 1997, and is consistent with the Commission's restructuring plan filing guidelines, the data contained in the exhibits is not "stale" for the purposes of this proceeding.

Mr. Reising's suggestion that PP&L be required to update its fully-distributed cost allocation study and functional unbundling analysis for a test period ended December 31, 1996, is unnecessary, of questionable analytical assistance and could result in a re-allocation of costs that would produce intra- and inter-class cost shifting, which is prohibited by the Act. In addition, such an exercise would be very *time-consuming* and would divert scarce Company and Commission resources.

Contrary to Mr. Reising's assertions, and as the above discussion clearly shows, Exhibits JMK 1 and 2 are internally consistent. Mr. Reising is correct, however, when he points out that page 26 of Exhibit JMK 2 does not reconcile to page 4 of that same exhibit. Those two pages do not reconcile for good reason. Page 4 of Exhibit JMK 2 is a summary of the results provided in Sections IV (page 95), V (page 177), VI (page 253) and VII (page 323) of that exhibit which show Commission-approved revenue requirements data at actual class rates of return. Page 26 of Exhibit JMK 2 shows revenue requirements data at equal class rates of return. The proper comparison would be pages 4 and 24 of Exhibit JMK 2. However, pages 24 and 25, as submitted on April 1, 1997 with PP&L's Restructuring Plan filing, reflect a data input error. Exhibit JMK 4, attached to this rebuttal testimony, provides revised pages 24 and 25 which correct this inadvertent data error.

Mr. Reising asserts that PP&L did not provide this clarification during discovery. However, Mr. Reising had the opportunity to seek clarification of issues, but, for unknown reasons, chose not to request such clarification. He should not criticize PP&L for his lack of effort.

Based on the foregoing discussion, Mr. Reising's unsubstantiated assertions regarding PP&L's cost allocation study, Exhibit JMK 1, and functional unbundling analysis, Exhibit JMK 2, should be rejected.

Q. Have you reviewed Mr. Baron's testimony regarding his proposed unbundling of PP&L's delivery charges into separate transmission and distribution components?

A. Yes, I have.

Q. What information will PP&L use to unbundle delivery charges into the applicable transmission and distribution components?

A. PP&L will use the results of the cost allocation study set forth in Exhibit JMK 2 to unbundle delivery charges into the transmission and distribution components. Section VI of that exhibit provides the details of the allocation of transmission-related capital and operating costs to rate classes. Section VII provides the details of the allocation of distribution-related capital and operating costs to rate classes.

Q. What costs do the Company's proposed delivery charges include?

A. The Company's proposed delivery charges include non-variable, non-energy-related transmission and distribution-related capital and operating costs. These delivery charges reflect a functional unbundling of PP&L's transmission and distribution revenue requirements which were established in the Company's most recent base rate case at Docket No. R-00943271. As Exhibit JMK 2 clearly shows, the calculation of these revenue requirements is based on the assignment of transmission and distribution-related costs on a capacity-related demand (KW) basis; not on customer energy (KWH) consumption. Because transmission and distribution revenue requirements reflect non-variable, non-energy-related costs, re-assignment or re-allocation of transmission and distribution-related costs on some other basis would result in intra- and inter-class cost shifting, which is inconsistent with the intent of the Act.

<u>Unrecovered Energy Costs</u>

Q. Have you reviewed the testimony of Messrs. Kollen, La Capra and Catlin regarding the amount of unrecovered PUC-jurisdictional energy costs that PP&L should be permitted to recover as stranded costs?

A. Yes, I have.

Q. Do you agree with the recommendations of Messrs. Kollen, La Capra and Catlin that PP&L's claim for recovery of its unrecovered on-going energy costs for the years 1997 and 1998, as part of its overall stranded costs claim, should be denied?

A. Absolutely not.

Q. Please explain.

A. On December 13, 1996, PP&L filed an application with the PUC requesting permission to roll into base rates its Energy Cost Rate (ECR) and State Tax Adjustment Surcharge (STAS). PP&L made this filing in response to the Act, particularly Section 2804(4) which establishes certain caps on utility rates.

In its filing, the Company also requested that the Commission determine that two categories of costs are "regulatory assets" or "other deferred charges" which are recoverable as "transition or stranded costs" under the Act. The first category is PP&L's actual undercollected PUC-jurisdictional energy costs as of December 31, 1996 which total $17.2 million. The second category is a normalized level of estimated future on-going PUC-jurisdictional energy costs. The Company estimated that its normalized level of future on-going PUC-jurisdictional energy costs would be approximately $31.5 million higher than the level of energy costs rolled into base rates. PP&L calculated this amount by taking an average of actual energy costs for a 5-year period from 1992 through 1996 and subtracting the level of energy costs included in retail customer base rates after the ECR roll-in.

Although Messrs. Kollen, La Capra and Catlin do not challenge PP&L's recovery of its actual undercollected PUC-jurisdictional energy cost balance of $17.2 million as of December 31, 1996, they recommend denial of the Company's claim to recover its estimated underrecovery of future on-going PUC-jurisdictional energy costs for the years 1997 and 1998. Messrs. Kollen, La Capra and Catlin allege that, in their opinions, PP&L has not provided enough supporting information to justify its claim. On the contrary, PP&L has provided appropriate support for its claim. For example, as part of its December 13, 1996 filing, the Company submitted a calculation which demonstrated that, based on a 5-year average of actual energy costs incurred for the years 1992 through 1996, the level of energy costs included in its base rates on January 1, 1997 as a result of the roll-in of its ECR pursuant to the Act, would be less than its estimated future on-going level of energy costs by approximately $31.5 million per year. Exhibit JMK 5, attached to this rebuttal testimony, provides a calculation of the 5-year average similar to that submitted with PP&L's December 13, 1996 filing. It should be noted that Exhibit JMK 5 revises the level of energy costs included in the Company's base rates after the roll-in of its ECR to correct an error identified in a Commission audit of the Company's energy cost supporting data. In addition, the data in Exhibit JMK 5 for calendar year 1996 was revised to exclude estimated data for the month of December 1996. As Exhibit JMK 5 shows, based on an average of PP&L's actual energy costs incurred for the 5-year period ended December 31, 1996, the Company will underrecover its future on-going level of energy costs for the years 1997 and 1998, when compared to the level included in existing base rates, by approximately $31.2 million per year.

Q. Please continue.

A. Exhibit JMK 6, which provides PP&L's energy cost data for calendar years 1997 and 1998, also shows that the Company will underrecover the level of energy costs in its base rates by about $36 million in 1997 and $67 million in 1998. The data for calendar year 1997 are based on actual energy costs incurred for the period January 1, 1997 through June 30, 1997 and estimated energy costs for the period July 1, 1997 through December 31, 1997. The energy cost data for 1998 are based on preliminary operating budget data for this calendar year which are consistent with PP&L's 1997 Annual Resource Planning Report. It should be noted that, based on actual energy costs incurred for the period January 1, 1997 through June 30, 1997, PP&L already has underrecovered the level of energy costs included in its base rates by $22.5 million for the year 1997.

Q. Have you reviewed Messrs. Kollen and La Capra's allegation that PP&L's calculation of its underrecovery for 1997 and 1998 is overstated?

A. Yes, I have. Messrs. Kollen and La Capra allege that PP&L's calculation of its underrecovery of future on-going energy costs for the years 1997 and 1998 is overstated because it is not based on a mills per kilowatt-hour determination of those energy costs. This allegation is inaccurate. In point of fact, the calculations shown in Exhibits JMK 5 and JMK 6 do reflect a mills per kilowatt-hour energy cost determination. Total system energy costs for each annual period are divided by total system sales to derive energy costs on a mills per kilowatt-hour basis. This mills per kilowatt-hour rate is multiplied by applicable retail sales for the annual period to obtain the level of PUC-jurisdictional energy costs actually incurred or estimated to be incurred. The level of PUC-jurisdictional energy costs is compared to the amount of energy costs included in retail customer base rates, after roll-in of the ECR, to determine the actual or estimated underrecovery of PUC-jurisdictional energy costs.

Q. What is your recommendation regarding PP&L's claim for recovery of its underrecovered PUC-jurisdictional energy costs for the years 1997 and 1998?

A. Based on the foregoing discussion and Exhibits JMK 5 and 6, it is clear that PP&L has fully supported its claim to recover its underrecovered PUC-jurisdictional energy costs for the years 1997 and 1998 as a part of its stranded cost claim in this proceeding. As these exhibits show, PP&L will underrecover its PUC-jurisdictional energy costs by more than $31.2 million in those years. For these reasons, the recommendations of Messrs. Kollen, La Capra and Catlin regarding PP&L's claim for stranded cost recovery of its underrecovered energy costs for the years 1997 and 1998 should be rejected.

Q. Do you agree with Mr. Catlin's assertion that PP&L's claim for recovery of its underrecovered PUC-jurisdictional energy costs for the years

1997 and 1998 is inappropriate because its pro forma 1996 return on common equity may be understated?

A. No, I do not. Although Mr. Catlin readily admits that he has not performed any revenue requirements analysis of PP&L's financial data for the 12 months ended December 31, 1996, he alleges that the return on common equity earned by PP&L for this period is understated. This allegation is inaccurate and unsupported.

In its Final Order, entered on September 27, 1995, in the Company's most recent base rate proceeding at Docket No. R-00943271, the Commission determined that PP&L's allowed rate of return on common equity should be 11.50%. This determination was made after a thorough review of the record evidence in that proceeding, including the expert testimony of several witnesses on the issue. For the 12 months ended December 31, 1996, PP&L's pro forma rate of return on common equity was 11.42%, as shown in the Company's response to RP-A.3. of the Commission's restructuring plan filing guidelines. This earned return on common equity is below the 11.50% allowed by this Commission, and certainly is within its reasonable range of common equity returns for Pennsylvania electric utilities.

In addition, PP&L's actual financial data for the 12 months ended December 31, 1996 does not include an amount for underrecovered energy costs. These costs are recorded on the Company's balance sheet as a "regulatory asset." They are not recorded as an operating expense on its income statement from which the earned return on common equity is determined. Moreover, as its response to RP-A.3. of the Commission's restructuring plan filing guidelines clearly shows, PP&L's actual financial data for the 12 months ended December 31, 1996 properly was adjusted (annualized and normalized) to place the Company's rate base, operating revenues, and operating expenses on a PUC-jurisdictional ratemaking basis, pursuant to the Commission's regulations at 52 Pa. Code § 71.1, et seq. Contrary to Mr. Catlin's allegation, PP&L's calendar year 1996 financial data reflects the appropriate ratemaking adjustments, hence its pro forma return on common equity is not understated.

Mr. Catlin has provided no support for his allegation that the Company's pro forma 1996 earned return on common equity is understated. Therefore, his assertion regarding PP&L's claim for recovery of its underrecovered PUC-jurisdictional energy costs for the years 1997 and 1998 is without merit and should be rejected.

CTC Reconciliation Process

Q. Have you reviewed Mr. Boonin's testimony regarding the CTC reconciliation process and his proposed reconciliation mechanism?

A. Yes, I have.

Q. Do you agree with Mr. Boonin's proposed reconciliation mechanism?

A. No, I do not.

Q. Please explain.

A. Section 2808(f) of the Act calls for a limited true-up of the CTC to reconcile CTC revenues with the level of CTC-recoverable costs approved by the Commission. The Act does not contemplate an annual recalculation of stranded costs to be collected through the CTC. Rather, the reconciliation contemplated by the Act is limited only to an annual true-up for changes in customer sales volumes from the level of sales that the Commission uses to establish the CTC initially. Under this approach, the utility and its customers will be assured that the collection of stranded costs through the CTC will be consistent with the Commission's order in this proceeding. This approach, which is relatively simple to implement, will not require re-litigation of the other complex restructuring issues which will be decided by the PUC in this proceeding.

Mr. Boonin proposes a reconciliation mechanism which appears to require reconciliation of the market price determined by the Commission in this proceeding with the market price as it varies over the CTC application period.

His proposal contrasts with the Company's proposed CTC reconciliation process which requires annual CTC revenue collections to be tracked and compared with the annual CTC collection levels authorized by the PUC. In addition, PP&L's proposal does not include the accrual of interest on either CTC undercollections or CTC overcollections. Those annual under or overcollections will be subject to review and verification by the Commission. In this way, PP&L's customers will be assured that the total amount recovered through the CTC is neither greater than or less than the total CTC-recoverable amount authorized by the PUC. Mr. Boonin's proposal would create a level of complexity to the CTC reconciliation process that is unnecessary and is inconsistent with the intent of the Act, as the foregoing discussion indicates. For this reason, Mr. Boonin's proposal should be rejected.

Q. Have you reviewed Mr. Baron's recommendations that, if the CTC recovery period is extended beyond seven years, the Company should extend the generation-related rate cap?

A. Yes, I have.

Q. Do you agree with Mr. Baron's recommendation?

A. The Company is willing to extend the generation-related rate cap voluntarily, but only if it is extended to coincide with the CTC recovery period extension.

<u>Allocation of CTC to Rate Classes</u>

Q. Have you reviewed Mr. Schoengold's proposal regarding the allocation of the CTC?

A. Yes, I have. Mr. Schoengold proposes to allocate the generation-related costs reflected in the CTC to customer classes on the basis of energy (KWH), rather than on the basis of demand (KW).

Q. Do you agree with Mr. Schoengold's proposal?

A. Absolutely not. As Mr. Schoengold acknowledges in his testimony (pages 25-26), the costs reflected in the CTC are associated with generation-related capital and operating costs. These costs, which currently are reflected in PP&L's Commission-approved retail customer rates, properly were allocated among customer classes on a demand (KW) basis in the Company's most recent base rate case at Docket No. R-00943271, as shown in Exhibits JMK 1 and JMK 2. The re-allocation of these costs on an energy (KWH) basis would result in intra- and inter-class cost shifting which is prohibited by the Act. Consequently, Mr. Schoengold's proposal to allocate the CTC among customer classes on an energy (KWH) basis should be rejected.

<u>Allocation of Nuclear Decommissioning Costs to Rate Classes</u>

Q. Have you reviewed Mr. Baron's assertion that PP&L is proposing to allocate nuclear decommissioning costs to customer classes on the basis of energy (KWH), rather than on the basis of demand (KW)?

A. Yes, I have.

Q. Is Mr. Baron's assertion correct?

A. No, it is not. I believe Mr. Baron's assertion results from a misinterpretation of PP&L's response to Question 11 of Interrogatories of the PP&L Industrial Customer Alliance, Set I, Dated April 25, 1997.

Q. Please explain.

A. In its most recent base rate case at Docket No. R-00943271, PP&L properly allocated its nuclear decommissioning costs among customer classes on the basis of demand (KW), as shown in Exhibit JMK 1. In the functional unbundling of its costs of providing PUC-jurisdictional electric service shown in Exhibit JMK 2, PP&L continued its demand (KW) allocation of nuclear decommissioning costs. PP&L's proposed tariff rates contained in Exhibit OGK 2 also reflect the level of nuclear decommissioning costs allocated among customer classes on a demand basis. These allocated costs would be recovered from customers on a KWH basis which is the same manner that they presently are recovered through customer rates. Consequently, there is no merit to Mr. Baron's assertion that PP&L changed its demand allocation of nuclear decommissioning costs among customer classes.

Delivery Charge Recovery of Nuclear Decommissioning Costs

Q. Have you reviewed Mr. Kollen's allegation that PP&L's proposed recovery of nuclear decommissioning costs as a component of its "wires" charge represents a "double" recovery of that expense?

A. Yes, I have.

Q. Do you agree with Mr. Kollen's allegation?

A. No, I do not. PP&L has proposed, as part of its Restructuring Plan filing, to recover nuclear decommissioning costs as a distribution-related component of its delivery charges. Although the PUC-jurisdictional portion of PP&L's estimate of its overall level of stranded costs includes an amount associated with nuclear decommissioning costs for presentation purposes, if the Commission accepts PP&L's proposal, it is the Company's intention to exclude that amount from its overall level of generation-related stranded costs recovered through the CTC. Nuclear decommissioning costs, which are a defined component of stranded costs under the Act, would be recovered from customers as a component of PP&L's proposed distribution-related delivery charges over the remaining life of the Susquehanna generating plant. This treatment would not result in a "double recovery" of such costs.

Q. Have you reviewed Mr. Biewald's recommendation that the Commission not permit recovery of nuclear decommissioning costs over the remaining life of the Susquehanna generating plant?

A. Yes, I have.

Q. Do you agree with this recommendation?

A. No, I do not. Mr. Biewald's recommendation is short-sighted and contrary to the public interest.

Nuclear decommissioning cost funding is an important public health and safety issue consistently recognized by the PUC. PP&L's proposal will ensure that nuclear decommissioning costs will continue to be recovered through rates set by the PUC. By retaining PUC oversight of funding of those costs, PP&L's proposal also will ensure adequate nuclear decommissioning cost funding both during and after the transition to retail competition.

For these reasons, Mr. Biewald's recommendation should be rejected.

<u>Stranded Cost Recovery of Fossil Decommissioning Costs</u>

Q. Have you reviewed the testimony of Messrs. Kollen, La Capra, and Catlin regarding stranded cost recovery of fossil decommissioning costs?

A. Yes, I have.

Q. Do you agree with Mr. Kollen's recommendation that PP&L's claim for stranded cost recovery of fossil decommissioning costs be disallowed?

A. No, I do not.

Q. Please explain.

A. Mr. Kollen has based his recommendation on the faulty premise that stranded cost recovery of fossil decommissioning costs is not permitted by the Act and that, consistent with the Penn-Sheraton decision, such costs are not recoverable under traditional regulation until they actually are incurred.

In point of fact, stranded cost recovery of fossil decommissioning costs is permitted by the Act. 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 recovery of nuclear generating plant decommissioning costs. Fossil decommissioning costs represent those costs to be incurred by a utility to retire (dismantle, demolish and dispose of) its existing fossil generating facilities, which are recoverable as stranded costs under the Act.

As I discussed previously, PP&L's overall estimate of stranded generation-related capital and operating costs was calculated on the basis of the revenue requirements methodology contemplated by the Act. Under this methodology, PP&L included the costs of decommissioning its existing fossil generating facilities in its calculation of generation-related capital and operating costs that would be recoverable under traditional regulation at the end of the lives of those facilities. In this way, the fossil decommissioning costs are reflected in the calculation at the point in time when they actually would be incurred. Consequently, stranded cost recovery of fossil decommissioning costs as calculated by use of the revenue requirements methodology is consistent with the timing issue addressed in the Penn-Sheraton decision.

In addition, Mr. Kollen suggests that because other generation suppliers incur fossil decommissioning costs, PP&L's claim for stranded cost recovery of such costs should be denied. I strongly disagree. Mr. Kollen fails to recognize that the owners/operators of non-Pennsylvania utility fossil generation facilities can provide for the cost of decommissioning over the lives of their facilities. Therefore, because of the PUC's historic reliance on the Penn-Sheraton decision to defer the recovery of fossil decommissioning costs until the costs actually incurred (cash vs. accrual accounting), Pennsylvania electric utilities are required to seek and obtain stranded cost recovery of those costs or be placed at a significant competitive disadvantage. Moreover, the failure to accrue for decommissioning costs over the lives of the fossil generating facilities which give rise to those costs is not in accordance with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts, which the PUC has adopted.

Based on the foregoing discussion, Mr. Kollen's recommendation that PP&L be denied stranded cost recovery of fossil decommissioning cost should be rejected.

Q. Do you agree with Messrs. La Capra's and Catlin's recommendations that PP&L's claim for stranded costs recovery of fossil decommissioning costs be denied?

A. No. For all of the reasons I previously indicated regarding Mr. Kollen's recommendation about stranded cost recovery of fossil decommissioning costs, Messrs. La Capra's and Catlin's recommendations also should be rejected.

Q. Have you reviewed Mr. Gruber's testimony regarding stranded cost recovery of fossil decommissioning costs and his recommendation that amounts recovered for these costs be placed in a trust fund?

A. Yes, I have.

Q. Do you agree with Mr. Gruber's recommendation?

A. No, I do not. Although Mr. Gruber does not challenge PP&L's proposed stranded cost recovery of fossil decommissioning costs, he does recommend that the Company be required to deposit amounts recovered in a separate, but non-qualified, trust fund. Amounts placed in the trust fund could not be accessible to the Company, except for actual fossil decommissioning costs incurred. This recommendation is inappropriate because PP&L bears all of the risk associated with the estimate of its fossil decommissioning costs. As I previously indicated, historically, Pennsylvania electric utilities were permitted to recover fossil decommissioning costs at the end of the lives of the generating facilities which give rise to those costs or when those costs actually were incurred. Under that approach, the actual decommissioning costs incurred were recovered through customer rates. However, the Act contemplates stranded cost recovery of the net present value of PP&L's estimate of its costs required to decommission its fossil generating facilities. Generally, decommissioning cost estimates have proven to be much lower than the actual costs incurred. Consequently, because PP&L must live with its estimate of fossil decommissioning costs, it should not be required to place amounts recovered as stranded costs in a trust fund. Rather, the Company should have those amounts available to use in conducting its ongoing business activities.

In addition, the segregation of amounts recovered for fossil decommissioning costs for each generating facility into separate trust funds would restrict PP&L's ability to shift funds among its fossil generating facilities to maximize the availability of those funds during actual decommissioning activities.

For these reasons, Mr. Gruber's recommendation that amounts recovered for fossil decommissioning be deposited into separate trust funds should be rejected.

<u>Allocation of Universal Service Program Costs to Rate Classes</u>

Q. Have you reviewed Mr. Reed's and Ms. Brockway's testimony regarding the re-allocation of universal service program costs to rate classes?

A. Yes, I have.

Q. Do you agree with Mr. Reed and Ms. Brockway that universal service program costs should be re-allocated to rate classes on an energy (KWH) basis?

A. No, I do not.

Q. Please explain.

A. Historically, PP&L's universal service program-type costs have been allocated to rate classes on a customer basis. That is, the allocation of these costs, which continually has been accepted by the PUC, was based on the number of customers in each rate class. This is clearly evident by analyzing Exhibit JMK 1 which, as I previously indicated, represents compliance with the results of the Commission's Final Order in the Company's most recent base rate proceeding at Docket No. R-00943271.

As I previously indicated, the results contained in Exhibit JMK 1 form the basis for existing retail customer rates. Consequently, a re-allocation of universal service program-type costs to rate classes on an energy (KWH) basis would be inconsistent with historic ratemaking practice and would produce intra- and inter-class cost shifting, which is prohibited by the Act.

For these reasons, Mr. Reed's and Ms. Brockway's recommended re-allocation of universal service program-type costs on an energy (KWH) basis, rather than Commission-accepted customer basis, should be rejected.

Mechanism for Generation Service Cost Recovery

Q. Have you reviewed the testimony of Messrs. Johnstone and Schoengold regarding the recovery of generation service costs incurred by an electric distribution utility acting as a provider of last resort?

A. Yes.

Q. At this time, can you provide additional information regarding PP&L's proposed mechanism for the recovery of generation service costs?

A. Yes. As I understand an electric distribution utility's obligations as provider of last resort, if a customer contracts for electricity (generation supply) and it is not delivered or if a customer does not choose an alternative generation supplier, the electric distribution utility, or a Commission-approved alternative supplier, must acquire electricity at prevailing market prices to serve that customer, but will be permitted to recover fully all reasonable costs incurred to provide that service. Under PP&L's proposed Tariff No. 201, this service is designated as Basic Utility Supply Service (BUSS).

Q. Has the Company developed a proposed mechanism for recovery of the costs that it will incur as provider of last resort?

A. The Company is in the process of developing an appropriate cost recovery mechanism for BUSS. It has been determined that the Company may need to utilize two different cost recovery mechanisms -- one to recover the costs of providing generation service to customers with hourly meters and another to recover the costs of providing generation service to customers without hourly meters.

Q. Why do you believe that different mechanisms may be appropriate?

A. Customers with hourly meters can elect to purchase electricity from different generation suppliers at different times of the day. Theoretically, such a customer could purchase from an alternative generation supplier during low-cost periods and purchase from PP&L, as the provider of last resort, during high-cost periods. To accurately reflect the costs that it has incurred to provide generation service to that customer, the Company may need to develop a mechanism that tracks costs on an hourly basis. Moreover, such customers may affect adversely the overall load factor of the aggregate of "last resort" customers, thereby raising the costs to serve them. Thus, use of a uniform average-cost mechanism could understate the costs actually imposed on the Company by that customer. On the other hand, a customer without an hourly meter cannot manage generation supply purchases between low-cost periods and high-cost periods. Accordingly, a uniform average-cost mechanism would be appropriate for recovering generation service-related costs from that customer.

Q. What is the Company's proposal for recovering generation service costs from customers with hourly meters?

A. PP&L does not have a proposal to submit at this time. The development of an hourly cost recovery mechanism raises many issues regarding the design and application of an appropriate mechanism. PP&L is continuing to study these issues and will submit a proposed mechanism as soon as it has been developed.

Q. Has PP&L developed a proposed cost recovery mechanism for generation service customers without hourly meters?

A. Yes. PP&L has developed a proposed mechanism which has been designated as the Purchase Generation Cost Rate (PGCR). Exhibit JMK 7, attached to this testimony, is a copy of the Company's proposed PGCR.

Q. Please describe the PGCR which is set forth in Exhibit JMK 7.

A. The Company's proposed PGCR is patterned after the energy cost rate (ECR) which major Pennsylvania electric utilities utilized for many years to recover the net cost of energy from retail customers. The PGCR would be established on an annual basis on March 1 of each year for application beginning April 1 of that year. The annual levelized rate would be a uniform charge collected on a per KWH basis from all BUSS customers.

Q. What costs are reflected in the PGCR?

A. The mechanism would reflect the Company's actual costs of obtaining electricity (generation supply) from the marketplace for customers receiving "last resort" service. These costs would include the "prevailing price" market of the electricity, as well as the costs of administering the Company's electricity procurement program.

Q. Will the PGCR be reconciled?

A. Yes. The revenues actually recovered from customers under the PGCR would be reconciled against the Company's actual costs of obtaining the electricity for "last resort" customers. Overcollections or undercollections would be reflected in a correction factor in the following year's PGCR, with interest.

Q. How will the rate cap imposed by the Act affect implementation of the PGCR?

A. Under the rate cap, PP&L's charges for providing electricity to customers who do not shop are capped at levels in effect as of January 1, 1997. If the PGCR (including the correction factor) results in generation service-related charges below the rate cap, no adjustment would be required. However, if the PGCR (including the correction factor) results in total generation service-related charges above the rate cap, an adjustment would be necessary. The Company proposes to make that adjustment as a single credit to the customer's total bill. The credit would be stated on a per KWH basis. Of course, when total generation service-related charges decline below the rate cap, the credit would be eliminated.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT JMK 4

FUTURE [illegible] YEAR COST ALLOCATION
COMPANY AND PPUC ADJUSTMENTS FOR COMPLIANCE FILING
UNBUNDLING OF COSTS TO CATEGORIES FOR INPUT TO RATE CLASSES

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION DETAILS - FUTURE TEST YEAR ENDED 9/30/95
REVENUE REQUIREMENTS @ ACTUAL CLASS RATES OF RETURN

ASSIGNMENT AND ALLOCATION TO UNBUNDLED COST CATEGORIES$1,000

		INPUT	ALLOC	OUTPUT	TOTAL PENNA. JURISDICTION	PRODUCTION COSTS NET ENERGY	PRODUCTION COSTS ALL OTHER	TRANSMISSION	DISTRIBUTION	TOTAL TRANS/DIST
1	REVENUE REQUIREMENTS EXCLUDING									
2	RETURN INCOME & GR REC TAX			TXDT	1,489,679	569,540	603,641	52,833	263,665	
3	DEMAND COMPONENT			TXDTD	586,492	19,688	443,394	52,864	70,546	
4	ENERGY COMPONENT			TXDTE	710,098	549,852	160,246	0	0	
5	CUSTOMER COMPONENT			TXDTC	193,088	0	0	-31	193,119	
6	RATE OF RETURN-PERCENT	RTRA			9.54	0.0	9.84	9.83	8.74	
7	RETURN ON RATE BASE			RTNA1	478,699	0	311,524	47,642	119,533	
8	DEMAND COMPONENT			RTNAD	410,050	0	302,502	47,642	59,906	
9	ENERGY COMPONENT			RTNAE	9,022	0	9,022	0	0	
10	CUSTOMER COMPONENT			RTNAC	59,627	0	0	0	59,627	
11	INCOME TAXES			TSF1	271,794	0	222,957	17,057	31,780	
12	DEMAND COMPONENT			TSF1D	235,233	0	201,764	17,304	16,165	
13	ENERGY COMPONENT			TSF1E	20,473	0	21,757	-195	-1,089	
14	CUSTOMER COMPONENT			TSF1C	16,088	0	-564	-52	16,704	
15	ANNUALIZATION REVENUES	ANN	K929		26,556	0	16,596	1,509	8,451	
16	DEMAND COMPONENT			ANN1D	14,602	-6,518	14,338	1,512	5,270	
17	ENERGY COMPONENT	ANN1E	RRBAE		8,767	6,518	2,264	-2	-13	
18	CUSTOMER COMPONENT	ANN1C	RRBAC		3,187	0	-6	-1	3,194	
19	LATE PAY CHARGES	S11	K929	R11	7,341	0	4,588	417	2,336	
20	DEMAND COMPONENT			R111D	4,036	-1,802	3,964	418	1,456	
21	ENERGY COMPONENT	R111E	RRBAE		2,424	1,802	626	-1	-3	
22	CUSTOMER COMPONENT	R111C	RRBAC		881	0	-2	0	883	
23	REVENUE REQTS BEFORE GRT			RRBA	2,206,275	569,540	1,116,938	115,606	404,191	
24	DEMAND COMPONENT			RRBAD	1,213,138	28,008	929,360	115,880	139,890	
25	ENERGY COMPONENT			RRBAE	728,402	541,532	188,135	-192	-1,073	
26	CUSTOMER COMPONENT			RRBAC	264,735	0	-556	-82	265,373	
27	GROSS RECEIPTS TAX @ 44 MILL			GRTA1	103,104	26,213	52,382	5,409	19,100	
28	DEMAND COMPONENT			GRTA1D	56,693	906	43,617	5,422	6,748	
29	ENERGY COMPONENT			GRTA1E	34,040	25,307	8,792	-9	-50	
30	CUSTOMER COMPONENT			GRTA1C	12,372	0	-26	-4	12,402	
31	TOTAL REVENUE REQUIREMENTS			RRA1	2,309,379	595,753	1,169,320	121,016	423,290	
32	DEMAND COMPONENT			RRA1D	1,269,830	28,914	972,975	121,303	146,638	
33	ENERGY COMPONENT			RRA1E	762,442	566,839	196,927	-201	-1,123	
34	CUSTOMER COMPONENT			RRA1C	277,107	0	-582	-85	277,774	

FUTURE [illegible] YEAR COST ALLOCATION
COMPANY [illegible] PPUC ADJUSTMENTS FOR COMPLIANCE FILING
UNBUNDLING OF COSTS TO CATEGORIES FOR INPUT TO RATE CLASSES

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION DETAILS - FUTURE TEST YEAR ENDED 9/30/95
CALCULATION OF INCOME TAXES FOR
REVENUE REQUIREMENTS @ ACTUAL CLASS RATES OF RETURN
ASSIGNMENT AND ALLOCATION TO UNBUNDLED COST CATEGORIES$1,000

	INPUT	ALLOC	OUTPUT	TOTAL PENNA. JURISDICTION	PRODUCTION COSTS NET ENERGY	PRODUCTION COSTS ALL OTHER	TRANSMISSION	DISTRIBUTION	TOTAL TRANS/DIST
1 AT SYSTEM % CLASS RATE OF RTN RTRA				9.54	0.0	9.84	9.83	8.74	
2 RETURN ON RATE BASE			RTNA1	478,699	0	311,524	47,642	119,533	
3 DEMAND COMPONENT			RTNAD	410,050	0	302,502	47,642	59,906	
4 ENERGY COMPONENT			RTNAE	9,022	0	9,022	0	0	
5 CUSTOMER COMPONENT			RTNAC	59,627	0	0	0	59,627	
6 ADJUSTMENT TO TAXABLE INCOME			TAT	-92,069	0	2,932	-23,534	-71,467	
7 DEMAND COMPONENT			TATD	-79,193	0	-20,827	-23,534	-34,832	
8 ENERGY COMPONENT			TATE	23,759	0	23,759	0	0	
9 CUSTOMER COMPONENT			TATC	-36,635	0	0	0	-36,635	
10 FEDERAL INCOME TAX ADJUSTMEN			TAFI	804	0	525	73	206	
11 DEMAND COMPONENT			TAFID	701	0	525	73	103	
12 ENERGY COMPONENT			TAFIE	0	0	0	0	0	
13 CUSTOMER COMPONENT			TAFIC	103	0	0	0	103	
14 STATE INCOME TAX ADJUSTMENT			TSTA	213	0	139	19	55	
15 DEMAND COMPONENT			TSTAD	186	0	139	19	28	
16 ENERGY COMPONENT			TSTAE	0	0	0	0	0	
17 CUSTOMER COMPONENT			TSTAC	27	0	0	0	27	
18 SUMMARY FOR FEDERAL INCOME									
19 TAX CALCULATION									
20 (2)+(6)+(10)+(14)			TFTI1	380,935	0	310,925	23,818	46,192	
21 DEMAND COMPONENT			TFTI1D	325,836	0	278,646	23,864	23,326	
22 ENERGY COMPONENT			TFTI1E	31,977	0	32,279	-46	-256	
23 CUSTOMER COMPONENT			TFTI1C	23,122	0	0	0	23,122	
24 FEDERAL INCOME TAX									
25 .35 / .65 X (20)+(10)			TFIT1	200,344	0	164,459	12,580	23,305	
26 DEMAND COMPONENT			TFIT1D	173,990	0	149,214	12,800	11,976	
27 ENERGY COMPONENT			TFIT1E	14,604	0	15,747	-174	-969	
28 CUSTOMER COMPONENT			TFIT1C	11,749	0	-502	-46	12,297	
29 ADJ TO STATE TAXABLE INCOME			TASI	83	0	47	-16	52	
30 DEMAND COMPONENT			TASID	-214	0	-99	-16	-99	
31 ENERGY COMPONENT			TASIE	147	0	147	0	0	
32 CUSTOMER COMPONENT			TASIC	151	0	0	0	151	
33 SUMMARY FOR STATE INCOME									
34 TAX CALCULATION									
35 (2)+(6)+(14)+(25)+(29)			TSTI1	586,137	0	478,393	36,627	71,117	
36 DEMAND COMPONENT			TSTI1D	503,686	0	430,221	36,847	36,618	
37 ENERGY COMPONENT			TSTI1E	47,532	0	48,675	-174	-969	
38 CUSTOMER COMPONENT			TSTI1C	34,919	0	-502	-46	35,467	
39 STATE INCOME TAX									
40 .1099 / .8901 X (35)+(14)			TSIT1	71,450	0	58,498	4,477	8,475	
41 DEMAND COMPONENT			TSIT1D	61,243	0	52,550	4,504	4,189	
42 ENERGY COMPONENT			TSIT1E	5,869	0	6,010	-21	-120	
43 CUSTOMER COMPONENT			TSIT1C	4,338	0	-62	-6	4,406	

EXHIBIT JMK 5

Calculation of Normalized
Energy Cost Level and Deferral Amount
($000)

Calendar Year Period	Total System	PUC Jurisdiction
1992	$585,266	$558,031
1993	567,436	541,261
1994	592,383	564,855
1995	569,125	543,337
1996	583,469	557,733
Normalized Level (5-yr. Avg.)	$579,536	$553,043
Less: *Amount in Base Rates* After ECR Roll-in	546,174	521,892
Deferral Amount	$33,362	$31,151

Pennsylvania Power & Light Company
Detailed Summary of Actual Energy Costs
For the Year Ended December 31, 1992

	MWH	Cost in thousands	Mill/KWH
Generation			
Nuclear (Includes D&D and Spent Fuel Expense)	12,216,273	$ 74,476	6.10
Coal (Includes Retired Miners Health Care)	25,152,636	438,572	17.44
Oil (incl. Sun Oil Adj.)	1,057,432	39,486	37.34
CTs and Diesels	9,696	727	74.98
Hydro	750,388	-	0.00
Total Generation	39,186,425	553,261	14.12
Purchased Power			
Other Utilities	980,537	23,894	24.37
Interchange - PJM	482,316	13,925	28.87
Qualified Facilities	3,884,190	237,679	61.19
Total Purchased Power	5,347,043	275,498	51.52
Less Off System Sales			
Interchange - PJM	5,160,278	110,677	21.45
Other Utilities	1,349,864	32,155	23.82
Atlantic Electric	746,052	14,371	19.26
Jersey Central Power & Light	4,361,328	59,292	13.59
Baltimore Gas & Electric	792,471	4,350	5.49
GPU Service Corporation	77,130	4,859	63.00
Total Off System Sales	12,487,123	225,704	18.07
System Cost of Power	32,046,345	603,055	18.82
Less Adjustments			
Sun Oil Adjustment		6,721	
Safe Harbor		9,415	
Borderline/Waste Heat		91	
Foregone Interchange Savings- Trans.Ent'mnts/Output Reserv.		1,562	
Total Adjustments		17,789	
Cost of Energy - "Fc"		$ 585,266	19.59
Net Energy Available	32,046,345		
Less: Line Losses	2,174,765		
Net Unbilled Sales	(607)		
Actual Sales - "St"	29,872,187		
Line Loss Percentage	6.8%		
Retail Sales	28,482,112		

Pennsylvania Power & Light Company
Detailed Summary of Actual Energy Costs
For the Year Ended December 31, 1993

	MWH	Cost in thousands	Mill/KWH
Generation			
Nuclear (Includes D&D and Spent Fuel Expense)	12,181,133	$ 76,628	6.29
Coal (Includes Retired Miners Health Care)	24,960,252	378,852	15.18
Oil (incl. Sun Oil Adj.)	1,451,849	56,525	38.93
CTs and Diesels	15,924	1,119	70.27
Hydro	636,677	-	0.00
Total Generation	39,245,835	513,124	13.07
Purchased Power			
Other Utilities	1,258,695	33,146	26.33
Interchange - PJM	603,736	16,543	27.40
Qualified Facilities	3,748,630	229,111	61.12
Total Purchased Power	5,611,061	278,800	49.69
Less Off System Sales			
Interchange - PJM	4,141,470	96,610	23.33
Other Utilities	1,121,557	26,171	23.33
Atlantic Electric	754,463	11,196	14.84
Jersey Central Power & Light	4,400,057	53,902	12.25
Baltimore Gas & Electric	790,174	4,309	5.45
GPU Service Corporation	75,938	4,784	63.00
Total Off System Sales	11,283,659	196,972	17.46
System Cost of Power	33,573,237	594,952	17.72
Less Adjustments			
Sun Oil Adjustment		6,864	
Safe Harbor		9,860	
Borderline/Waste Heat		56	
Foregone Interchange Savings- Trans.Ent'mnts/Output Reserv.		(181)	
Prior Period Cr. incl in pur power - other		(72)	
Retired Miners Health Care Adj.		10,989	
Total Adjustments		27,516	
Cost of Energy - "Fc"		$ 567,436	18.20
Net Energy Available	33,573,237		
Less: Line Losses	2,149,239		
Net Unbilled Sales	250,985		
Actual Sales - "St"	31,173,013		
Line Loss Percentage	6.4%		
Retail Sales	29,735,045		

Pennsylvania Power & Light Company
Detailed Summary of Actual Energy Costs
For the Year Ended December 31, 1994

	MWH	Cost in thousands	Mill/KWH
Generation			
Nuclear (Includes D&D and Spent Fuel Expense)	13,779,160	$ 81,406	5.91
Coal (Includes Retired Miners Health Care)	21,537,071	318,796	14.80
Oil (incl. Sun Oil Adj.)	1,764,056	69,092	39.17
CTs and Diesels	40,375	2,556	63.31
Hydro	753,100	-	0.00
Total Generation	37,873,762	471,850	12.46
Purchased Power			
Other Utilities	1,526,474	39,436	25.83
Interchange - PJM	1,016,888	29,706	29.21
Qualified Facilities	3,519,702	218,174	61.99
Total Purchased Power	6,063,064	287,316	47.39
Less Off System Sales			
Interchange - PJM	3,158,227	75,756	23.99
Other Utilities	425,000	9,154	21.54
Atlantic Electric	651,930	9,754	14.96
Jersey Central Power & Light	4,265,165	50,999	11.96
Baltimore Gas & Electric	893,893	4,524	5.06
GPU Service Corporation	71,427	4,500	63.00
Total Off System Sales	9,465,642	154,687	16.34
System Cost of Power	34,471,184	604,479	17.54
Less Adjustments			
Sun Oil Adjustment		6,003	
Safe Harbor		9,623	
Borderline/Waste Heat		113	
Retired Miners Health Care Adj.		(3,643)	
Total Adjustments		12,096	
Cost of Energy - "Fc"		$ 592,383	18.26
Net Energy Available	34,471,184		
Less: Line Losses	2,160,381		
Net Unbilled Sales	(127,737)		
Actual Sales - "St"	32,438,540		
Line Loss Percentage	6.3%		
Retail Sales	30,931,132		

Pennsylvania Power & Light Company
Detailed Summary of Actual Energy Costs
For the Year Ended December 31, 1995

	MWH	Cost in thousands	Mill/KWH
Generation			
Nuclear (Includes D&D and Spent Fuel Expense)	14,056,497	$ 71,155	5.06
Coal (Includes Retired Miners Health Care)	23,110,942	336,080	14.54
Oil (incl. Sun Oil Adj.)	1,032,781	41,114	39.81
CTs and Diesels	24,726	1,524	61.64
Hydro	600,358	-	0.00
Emission Allowances Consumed	0	1,063	N/A
Total Generation	38,825,284	450,936	11.61
Purchased Power			
Other Utilities	2,246,981	55,946	24.90
Interchange - PJM	846,375	19,343	22.85
Qualified Facilities	3,506,292	216,779	61.83
Total Purchased Power	6,599,648	292,068	44.26
Less Off System Sales			
Interchange - PJM	2,358,134	52,003	22.05
Other Utilities	1,667,120	39,417	23.64
Atlantic Electric	698,720	10,240	14.66
Jersey Central Power & Light	4,367,830	48,365	11.07
Baltimore Gas & Electric	911,886	4,025	4.41
GPU Service Corporation	30,544	1,924	62.99
Total Off System Sales	10,034,234	155,974	15.54
System Cost of Power	35,390,698	587,030	16.59
Less Adjustments			
Sun Oil Adjustment		7,397	
Safe Harbor		9,433	
Borderline/Waste Heat		96	
Foregone Interchange Savings- Trans.Ent'mnts/Output Reserv.		651	
Price Response Service Adjustment		328	
Total Adjustments		17,905	
Cost of Energy - "Fc"		$ 569,125	17.38
Net Energy Available	35,390,698		
Less: Line Losses	2,361,231		
Net Unbilled Sales	234,731		
Company Use	29,718		
Price Response Service Adjustment	18,615		
Actual Sales - "St"	32,746,403		
Line Loss Percentage	6.7%		
Retail Sales	31,262,590		

Pennsylvania Power & Light Company
Detailed Summary of Actual Energy Costs
For the Year Ended December 31, 1996

	MWH	Cost in thousands	Mill/KWH
Generation			
Nuclear (Includes D&D and Spent Fuel Expense)	15,192,060	$ 76,367	5.03
Coal (Includes Retired Miners Health Care)	22,485,491	329,507	14.65
Oil (incl. Sun Oil Adj.)	963,475	41,373	42.94
CTs and Diesels	18,354	1,256	68.43
Hydro	771,190	513	0.67
Emission Allowances Consumed		1,179	N/A
Fuel Oil Litigation Settlement		(1,742)	N/A
Total Generation	39,430,570	448,453	11.37
Purchased Power			
Other Utilities	4,535,100	95,908	21.15
Interchange - PJM	1,631,082	45,011	27.60
Qualified Facilities (a)	3,366,077	209,693	62.30
Total Purchased Power	9,532,259	350,612	36.78
Less Off System Sales			
Interchange - PJM	1,338,299	28,248	21.11
Other Utilities	6,342,469	125,691	19.82
Atlantic Electric	655,468	9,688	14.78
Jersey Central Power & Light	3,535,378	39,431	11.15
Baltimore Gas & Electric	985,585	5,040	5.11
Total Off System Sales	12,857,199	208,098	16.19
System Cost of Power	36,105,630	590,967	16.37
Less Adjustments			
Sun Oil Adjustment		5,334	
Safe Harbor		10,111	
Borderline/Waste Heat		96	
Foregone Interchange Savings- Trans.Ent'mnts/Output Reserv.		379	
Price Response Service Adjustment (A)		3,051	
Retired Miners Health Care Adj.		(1,764)	
Energy Savings Associated with Phase Out of Expiring Bulk Power Agreement		(9,709)	
Total Adjustments		7,498	
Cost of Energy - "Fc"		$ 583,469	17.35
Net Energy Available	36,105,630		
Less: Line Losses	2,361,991		
Net Unbilled Sales	(173,548)		
Company Use	126,695		
Price Response Service Adjustment	163,044		
Actual Sales - "St"	33,627,448		
Line Loss Percentage	6.5%		
Retail Sales	32,144,187		

EXHIBIT JMK 6

Calculation of Estimated Unrecovered Energy Costs
For the Years 1997 and 1998
($000)

	1997	1998
A. Total System Sales - MWH	32,953,365	34,080,598
B. Total System Energy Costs	$579,915	$610,454
C. Total System Energy Costs - Mills/KWH	17.598	17.912
D. PUC Jurisdiction Sales - MWH	31,718,974	32,900,730
E. PUC Jurisdiction Energy Costs (DxC)	$558,192	$589,320
F. Amount of Energy Costs in Base Rates After ECR Roll-In	$521,892	$521,892
G. Unrecovered Energy Costs (E-F)	$36,300	$67,428

Pennsylvania Power & Light Company
Detailed Summary of Actual/Estimated Energy Costs
For the Year Ended December 31, 1997 *

	MWH	Cost in thousands	Mill/KWH
Generation			
Nuclear (Includes D&D and Spent Fuel Expense)	14,485,765	$ 74,064	5.11
Coal (Includes Retired Miners Health Care)	23,509,146	342,510	14.57
Oil/Gas	792,648	27,052	34.13
CTs and Diesels	14,106	658	46.65
Hydro	648,454	-	0.00
Emission Allowances Consumed	0	2,243	N/A
Fuel Oil Dealers Settlement	0	(445)	N/A
Total Generation	39,450,119	446,082	11.31
Purchased Power			
Other Utilities	5,144,177	120,968	23.52
Interchange - PJM	1,245,845	30,773	24.70
Qualified Facilities	2,768,295	194,045	70.10
Total Purchased Power	9,158,317	345,786	37.76
Less Off System Sales			
PJM	1,087,945	22,784	20.94
Other Utilities	6,745,933	134,828	19.99
Atlantic City Electric	679,183	10,191	15.00
Jersey Central Power & Light	3,336,266	36,689	11.00
Baltimore Gas & Electric	940,421	4,888	5.20
Total Off System Sales	12,789,748	209,380	16.37
System Cost of Power	35,818,688	582,488	16.26
Less Adjustments			
Safe Harbor		9,996	
Borderline/Waste Heat		111	
Price Response Service Adjustment		4,013	
Energy Savings Associated with Phase Out of Expiring Bulk Power Agreement		(11,547)	
Total Adjustments		2,573	
Cost of Energy - "Fc"		$ 579,915	17.60
Net Energy Available	35,818,688		
Less: Line Losses	2,298,762		
Net Unbilled Sales	196,880		
Company Use	154,327		
Price Response Service Adjustment	215,354		
Actual Sales - "St"	32,953,365		
Line Loss Percentage	6.4%		
Retail Sales	31,718,974		

* Six months actual, six months estimate

Pennsylvania P[illegible] Light Company
Summary of Actu[illegible] Costs and Sales
Net System [illegible] Requirements
For the Year 1997*

	ACTUAL						ESTIMATED						
	January	February	March	April	May	June	July	August	September	October	November	December	Total
Generation													
Nuclear	1,473,867	1,220,756	600,955	713,396	1,186,757	1,420,834	1,325,800	1,325,800	1,283,000	1,325,800	1,283,000	1,325,800	14,485,765
Coal	2,248,423	1,848,356	1,900,243	1,846,749	1,598,749	2,229,126	2,103,600	2,114,500	1,877,800	1,949,900	1,655,000	2,136,700	23,509,146
Oil/Gas	127,258	(2,643) (B)	(3,815) (B)	(25) (B)	4,786	139,087	200,300	190,000	101,100	1,000	6,400	29,200	792,648
CTs & Diesels	241	98	394	138	257	2,778	5,100	1,700	2,500	300	300	300	14,106
Hydro	64,722	62,271	78,772	62,912	64,216	55,961	43,100	34,500	31,200	37,000	51,500	62,300	648,454
Total Generation	3,914,511	3,128,838	2,576,549	2,623,170	2,854,765	3,847,786	3,677,900	3,666,500	3,295,600	3,314,000	2,996,200	3,554,300	39,450,119
Purchased Power													
Other Utilities	607,246	507,391	830,740	578,185	741,038	613,577	117,600	112,900	112,100	167,400	346,800	409,200	5,144,177
PJM	237,079	246,381	328,794	141,604	85,423	43,864	15,200	10,600	9,800	15,000	57,100	55,000	1,245,845
Qualified Facilities	240,513	246,691	237,990	236,121	257,113	243,867	224,300	224,300	216,600	224,500	204,500	211,800	2,768,295
Total Purchased Power	1,084,838	1,000,463	1,397,524	955,910	1,083,574	901,308	357,100	347,800	338,500	406,900	608,400	676,000	9,158,317
Off System Sales													
PJM	(30,713)	(24,708)	(21,688)	(40,991)	(133,909)	(314,136)	(117,700)	(156,100)	(131,100)	(54,300)	(24,600)	(38,000)	(1,087,945)
Other Utilities	(984,978)	(737,973)	(640,735)	(516,511)	(836,045)	(1,127,091)	(396,100)	(378,100)	(375,300)	(374,100)	(153,000)	(226,000)	(6,745,933)
Atlantic City Electric	(65,166)	(51,934)	(55,209)	(50,945)	(45,154)	(61,875)	(62,000)	(62,300)	(56,300)	(58,100)	(47,100)	(63,100)	(679,183)
Jersey Central Power & Light	(264,187)	(209,129)	(170,830)	(172,054)	(191,688)	(252,978)	(229,600)	(230,200)	(205,500)	(206,700)	(200,200)	(232,600)	(2,565,666)
New Jersey Central Power & Light						(108,000)	(111,600)	(111,600)	(108,000)	(111,800)	(108,000)	(111,600)	(770,600)
Baltimore Gas & Electric	(95,622)	(79,197)	(38,966)	(46,267)	(76,987)	(92,182)	(86,200)	(86,200)	(83,200)	(86,200)	(83,200)	(86,200)	(940,421)
Total Off System Sales	(1,440,666)	(1,102,941)	(927,428)	(826,768)	(1,283,783)	(1,956,262)	(1,003,200)	(1,024,500)	(959,400)	(891,200)	(616,100)	(757,500)	(12,789,748)
Net Energy Available	3,558,683	3,026,360	3,046,645	2,752,312	2,654,556	2,792,832	3,031,800	2,989,800	2,674,700	2,829,700	2,988,500	3,472,800	35,818,688
Less: Line Losses	37,628	258,364	111,045	149,215	236,151	149,618	297,356	227,628	127,982	183,734	201,896	318,145	2,298,762
Net Unbilled Sales	267,249	(438,076)	112,590	(128,720)	(136,826)	133,068	87,346	76,369	(131,820)	94,542	182,431	76,727	196,880
Company Use	13,856	13,344	11,779	9,803	10,155	8,230	14,040	13,800	13,740	13,810	14,840	16,930	154,327
Price Response Service Adjustment (A)	11,914	21,740	12,088	12,088	27,571	15,953	19,000	19,000	19,000	19,000	19,000	19,000	215,354
Actual Sales - "S_i"	3,228,036	3,170,988	2,799,143	2,707,926	2,517,505	2,485,963	2,614,058	2,653,003	2,645,798	2,518,614	2,570,333	3,041,998	32,953,365
Line Loss Percentage	1.1%	8.5%	3.6%	5.4%	8.9%	5.4%	9.8%	7.6%	4.8%	6.5%	6.8%	9.2%	6.4%

* Six months actual, six months estimate
(A) Price Response Service adjustment figures provided are for the previous month.
(B) Oil/Gas Generation was not being used due to the mild weather.

Pennsylvania Power & Light Comp
Summary of Actual Energy Costs an
Net System Costs
For the 12 Months Ended December 31,

	Actual						Estimated						
	1997 January	1997 February	1997 March	1997 April	1997 May	1997 June	1997 July	1997 August	1997 September	1997 October	1997 November	1997 December	Cal Year 1997
Generation													
Nuclear (Incl. D&D Exp. & Spent Fuel)	7,248,300	6,227,692	3,239,247	3,715,135	6,038,639	7,212,147	6,800,000	6,800,000	6,587,000	6,809,000	6,587,000	6,800,000	74,064,160
Coal (incl. Ret. Miners' Health Care)	32,983,719	27,592,635	27,752,329	26,605,860	23,401,836	31,974,629	30,559,400	30,647,200	27,367,600	28,302,500	24,098,500	31,223,900	342,510,108
Oil/Gas (Incl. Sun Oil Adj.)	4,937,216	319,852	84,425	164,879	368,170	5,203,547	5,796,700	5,535,400	3,139,900	55,400	326,700	1,120,300	27,052,289
CTs & Diesels	17,180	5,686	27,131	7,350	27,647	189,723	166,000	100,000	82,000	10,000	10,000	15,000	657,717
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-
Emission Allowances Consumed	156,130	115,777	122,656	140,240	523,376	(167,050)	244,600	245,600	203,100	204,200	203,600	250,900	2,243,329
Fuel Oil Litigation Settlement						(444,925)							(444,925)
Total Generation	45,342,545	34,261,442	31,225,788	30,833,484	30,359,668	43,968,071	43,566,700	43,326,200	37,379,600	35,381,100	31,226,000	39,410,100	446,082,676
Purchased Power													-
Other Utilities	17,106,975	13,745,960	17,713,900	14,850,346	16,004,784	14,129,075	2,934,000	2,578,400	2,765,300	3,766,200	6,615,400	8,735,300	120,967,640
PJM	7,047,461	5,508,166	7,062,983	3,525,136	2,414,580	1,694,714	386,100	245,900	247,900	345,000	1,102,000	1,193,500	30,773,440
Qualified Facilities	15,101,229	16,040,681	16,679,631	16,495,442	17,787,331	16,765,262	16,186,600	16,186,600	15,687,500	16,199,800	15,215,600	15,899,100	194,044,776
Total Purchased Power	39,255,665	35,294,807	41,456,514	34,870,924	36,206,695	32,589,051	19,506,700	19,010,900	18,700,700	20,333,000	22,933,000	25,827,900	345,785,856
Off System Sales													-
PJM	(1,347,275)	(582,927)	(447,527)	(708,140)	(2,021,973)	(6,993,981)	(2,507,000)	(3,137,600)	(2,779,300)	(1,081,600)	(435,400)	(741,000)	(22,783,723)
Other Utilities	(23,215,149)	(13,848,725)	(11,891,094)	(10,327,709)	(14,722,473)	(22,571,823)	(8,277,700)	(7,521,800)	(7,812,800)	(7,398,500)	(2,901,600)	(4,338,300)	(134,827,673)
Atlantic City Electric	(921,406)	(865,104)	(858,130)	(801,072)	(593,979)	(927,852)	(924,700)	(926,400)	(837,100)	(881,300)	(709,000)	(945,300)	(10,191,343)
Jersey Central Power & Light	(2,930,243)	(2,440,766)	(2,126,308)	(2,084,425)	(1,615,695)	(2,961,694)	(2,520,100)	(2,558,300)	(2,134,900)	(2,037,200)	(2,071,600)	(2,521,300)	(26,202,751)
Jersey Central Power & Light	-	-	-	-	-	(1,294,263)	(1,286,000)	(1,279,700)	(1,183,600)	(1,150,500)	(1,086,600)	(1,205,600)	(8,486,463)
Martins Creek Sale	-												-
Baltimore Gas & Electric	(476,368)	(411,028)	(213,790)	(245,199)	(398,550)	(476,002)	(448,800)	(448,800)	(434,800)	(449,500)	(434,800)	(446,800)	(4,888,457)
Total Off System Sales	(28,892,461)	(18,168,570)	(15,536,849)	(14,166,545)	(19,552,870)	(35,225,615)	(15,964,300)	(15,872,600)	(15,182,700)	(12,978,600)	(7,639,000)	(10,200,300)	(209,380,410)
System Cost of Power	55,705,749	51,387,679	57,145,453	51,337,843	47,013,493	41,331,507	47,109,100	46,466,500	40,897,600	42,735,500	46,520,000	54,837,700	582,468,124
Less Adjustments													
Safe Harbor	882,700	940,400	1,640,000	1,611,400	1,196,400	666,900	435,600	300,000	276,900	429,800	701,000	914,400	9,995,500
Borderline/Waste Heat	3,456	19,529	3,574	3,456	14,746	3,468	10,500	10,500	10,500	10,500	10,500	10,500	111,229
Price Response Service Adjusment	254,467	518,571	719,254	719,254	66,918	(67,740)	300,000	300,000	300,000	300,000	300,000	300,000	4,012,722
Energy Savings Associated with Phase													-
Out of Expiring Bulk Power Agreemen	(1,796,707)	(1,122,944)	(785,380)	(725,257)	(1,080,372)	(1,526,600)	(819,400)	(713,200)	(757,600)	(772,300)	(601,700)	(845,100)	(11,546,560)
Total Adjustments	(656,084)	355,556	1,577,446	1,608,853	199,690	(923,972)	(73,300)	(102,700)	(170,200)	(32,000)	409,800	379,800	2,572,891
Net Energy Cost	56,361,833	51,032,123	55,568,005	49,728,990	46,813,803	42,255,479	47,182,400	46,569,200	41,067,800	42,767,500	46,110,200	54,457,900	579,915,233

Pennsylvania P[illegible]r & Light Company
Summary of Act[illegible]gy Costs and Sales
Mi[illegible]KWH
For the Year 1997*

	ACTUAL						ESTIMATED						
	January	February	March	April	May	June **	July	August	September	October	November	December	Average
Generation													
Nuclear (excl. D&D Exp &Spent Fuel)	3.83	3.98	4.07	3.85	3.96	3.98	4.00	4.00	4.00	4.00	4.00	4.00	3.98
Coal (excl. Ret. Miners' Health Care)	14.61	14.85	14.53	14.33	14.56	14.28	14.53	14.49	14.57	14.51	14.56	14.61	14.53
Oil/Gas	38.80	(120.94) (A)	(22.13) (A)	(6,595.16) (A)	76.93	37.41	28.94	29.13	31.06	55.40	51.05	38.37	34.13
CTs & Diesels	71.29	58.02	66.86	53.28	107.58 (B)	68.29	32.55	58.82	32.80	33.33	33.33	50.00	46.63
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Generation	11.14	10.47	11.76	11.28	10.12	10.99	11.44	11.41	10.90	10.22	9.93	10.67	10.87
Purchased Power													
Other Utilities	26.17	27.09	21.32	25.68	21.60	23.03	24.95	22.84	24.67	22.63	19.08	21.35	23.52
PJM	29.73	22.36	21.48	24.89	28.27	38.64	25.40	23.20	25.30	23.00	19.30	21.70	24.70
Qualified Facilities	62.79	65.02	70.09	69.86	69.18	68.75	72.16	72.16	72.43	72.16	74.40	74.12	70.10
Total Purchased Power	36.19	35.28	29.66	36.48	33.41	36.16	54.63	54.66	55.25	49.97	37.69	37.91	37.76
Off System Sales													
PJM	43.87	23.59	20.63	17.28	15.10	22.26	21.30	20.10	21.20	19.92	17.70	19.50	20.94
Other Utilities	23.57	18.77	18.56	20.00	17.61	20.03	20.90	19.89	20.62	19.78	18.96	19.20	19.99
Atlantic City Electric	14.14	17.04	15.54	15.72	13.15	15.00	14.91	14.67	14.87	14.82	15.05	14.98	15.01
Jersey Central Power & Light	11.09	11.67	12.45	12.11	9.47	11.71	10.98	11.11	10.39	9.86	10.35	10.84	10.89
New Jersey Central Power & Light	0.00	0.00	0.00	0.00	0.00	11.98	11.52	11.47	10.96	10.29	10.06	10.80	11.01
Baltimore Gas & Electric	5.00	5.19	5.49	5.30	5.18	5.16	5.21	5.21	5.23	5.21	5.23	5.21	5.20
Total Off System Sales	20.05	16.47	16.75	17.13	15.23	18.01	15.91	15.49	15.83	14.56	12.40	13.47	16.37
System Cost of Power	15.65	18.98	18.76	18.65	17.71	14.80	15.54	15.54	15.29	15.10	15.57	15.79	16.26
Net Energy Cost	15.33	16.49	17.98	17.80	17.23	14.58	15.29	15.34	15.07	14.84	15.23	15.44	15.87

* Six months actual, six months estimate
** The effects of the Fuel Oil Litigation are not included in the individual generation categories, but are reflected in the totals.
(A) Net System Costs include adjustments from prior months. Oil/Gas Generation was not being used due to the mild weather.
(B) Many of the CTs were not running in April. More fuel was used and lower generation produced in May to start them up again, causing a variance in mills/KWH.

Exhibit JMK 6
Page 5 of 33

Pennsylvania P[illegible] & Light Company
Detailed Summary of Actu[illegible]ased Power and Interchange
MWH Acquired Thro[illegible]urchase & Interchange
For the Year 1997*

Source of Energy	ACTUAL						ESTIMATED						
	January	February	March	April	May	June	July	August	September	October	November	December	Total
Purchased Power:													
Other Utilities	607,246	507,391	830,740	578,185	741,038	613,577	117,600	112,900	112,100	167,400	346,800	409,200	5,144,177
Interchange Power:													
Receipts - PJM	237,079	246,381	328,794	141,604	85,423	43,864	15,200	10,600	9,800	15,000	57,100	55,000	1,245,845
Deliveries													
PJM	(30,713)	(24,708)	(21,688)	(40,991)	(133,909)	(314,136)	(117,700)	(156,100)	(131,100)	(54,300)	(24,600)	(38,000)	(1,087,945)
Other Utilities	(984,978)	(737,973)	(640,735)	(516,511)	(836,045)	(1,127,091)	(396,100)	(378,100)	(375,300)	(374,100)	(153,000)	(226,000)	(6,745,933)
Net Interchange Power	(778,612)	(516,300)	(333,629)	(415,898)	(884,531)	(1,397,363)	(498,600)	(523,600)	(496,600)	(413,400)	(120,500)	(209,000)	(6,588,033)
Qualified Facilities:													
Hammermill	11,902	11,681	11,294	11,388	13,389	15,158	12,500	12,500	12,100	12,500	-	-	124,412
Windmills, Hydro & Other	955	1,361	947	1,203	1,104	1,047	500	500	500	500	500	500	9,617
Paxton Creek	2,239	188	2	184	210	1,621	1,000	1,000	800	1,000	800	1,100	10,144
Harrisburg Steam	1,948	2,547	2,512	2,298	2,016	2,280	2,600	2,600	2,500	2,600	2,500	2,600	29,001
Gilberton	45,004	55,811	53,581	56,471	58,072	52,272	54,200	54,200	52,400	54,300	52,400	54,200	642,911
Koppers	4,777	5,283	4,847	4,197	3,977	4,856	4,600	4,600	4,400	4,600	4,400	4,600	55,137
Viking Energy	11,790	10,882	9,544	10,442	12,517	10,813	10,900	10,900	10,400	10,900	10,400	10,800	130,288
Archbald (A)	3,111	17,209	10,381	9,661	10,046	10,689	-	-	-	-	-	-	61,097
Frackville Energy	31,247	30,380	28,497	30,470	29,431	27,636	29,200	29,200	28,200	29,200	28,200	29,200	350,861
Continental (B)	11,493	-	-	-	-	-	-	-	-	-	-	-	11,493
NEPCO	27,033	24,013	29,934	27,564	30,779	28,217	29,100	29,100	28,200	29,100	28,200	29,100	340,340
Schuylkill Energy	57,661	54,647	53,932	57,437	62,006	53,918	49,900	49,900	48,300	50,000	48,300	49,900	635,901
Foster Wheeler	27,038	27,913	28,475	20,331	28,919	31,190	26,000	26,000	25,100	26,000	25,100	26,000	318,066
Taylor Energy	879	955	804	866	924	798	600	600	600	600	600	600	8,826
Keystone Energy	3,436	3,821	3,240	3,609	3,723	3,372	3,200	3,200	3,100	3,200	3,100	3,200	40,201
Total Qualified Facilities	240,513	246,691	237,990	236,121	257,113	243,867	224,300	224,300	216,600	224,500	204,500	211,800	2,768,295
Total Purchase & Interchange	69,147	237,782	735,101	398,408	113,620	(539,919)	(156,700)	(186,400)	(167,900)	(21,500)	430,800	412,000	1,324,439

* Six months actual, six months estimate

(A) PP&L's budget reflects the buyout of the Archbald contract. PP&L's actual books will reflect this beginning in July 1997 with the first of 49 monthly payments.

(B) PP&L bought out the Continental contract, which is being paid in five annual installments. The first installment of $16,170,000 was paid in February and is being allocated throughout the year.

Pennsylvania Power & Light Company
Detailed Summary of Actual Purchased Power and Interchange
Cost of Purchased and Interchange Power
For the Year 1997*

	ACTUAL						ESTIMATED						
Source of Energy	January	February	March	April	May	June	July	August	September	October	November	December	Total
Purchased Power:													
Other Utilities													
Energy Cost	$ 16,223,807	$ 12,805,031	$ 16,073,313	$13,238,478	$ 14,807,763	$ 13,461,695	$ 2,497,900	$ 2,277,900	$ 2,487,900	$ 3,357,900	$ 5,913,900	$ 7,820,400	$110,965,987
Demand Cost (A)	883,168	940,929	1,640,587	1,611,868	1,197,021	667,380	436,100	300,500	277,400	430,300	701,500	914,900	10,001,653
Total Other Utilities	17,106,975	13,745,960	17,713,900	14,850,346	16,004,784	14,129,075	2,934,000	2,578,400	2,765,300	3,788,200	6,615,400	8,735,300	120,967,640
Interchange Power:													
Receipts - PJM	7,047,461	5,506,166	7,062,983	3,525,136	2,414,580	1,694,714	386,100	245,900	247,900	345,000	1,102,000	1,193,500	30,773,440
Deliveries													
PJM	(1,347,275)	(582,927)	(447,527)	(708,140)	(2,021,973)	(6,993,981)	(2,507,000)	(3,137,600)	(2,779,300)	(1,081,600)	(435,400)	(741,000)	(22,783,723)
Other Utilities	(23,215,149)	(13,848,725)	(11,891,094)	(10,327,709)	(14,722,473)	(22,571,823)	(8,277,700)	(7,521,800)	(7,812,800)	(7,398,500)	(2,901,600)	(4,338,300)	(134,827,673)
Net Interchange Power	(17,514,963)	(8,923,486)	(5,275,638)	(7,510,713)	(14,329,866)	(27,871,090)	(10,398,600)	(10,413,500)	(10,344,200)	(8,135,100)	(2,235,000)	(3,885,800)	(126,837,956)
Qualified Facilities													
Hammermill	444,389	446,391	432,030	427,161	516,634	573,328	487,500	487,500	471,900	487,500	-	-	4,774,333
Windmills, Hydro & Other	57,304	61,667	56,814	72,173	66,249	62,825	27,000	27,000	27,000	27,000	27,000	27,000	559,032
Paxton Creek (B)	41,507	42,585	151,079	73,262	47,505	56,195	83,300	83,300	59,000	83,300	59,000	83,300	863,333
Harrisburg Steam	116,680	152,820	150,720	137,880	120,960	136,800	156,000	156,000	150,000	156,000	150,000	156,000	1,740,060
Gilberton	2,969,198	3,681,623	3,532,033	3,725,508	3,830,933	3,447,245	3,577,200	3,577,200	3,458,400	3,583,800	3,458,400	3,577,200	42,418,740
Koppers	286,277	314,427	287,890	250,652	238,280	290,905	266,800	266,800	255,200	266,800	255,200	266,800	3,246,031
Viking Energy	778,140	718,212	629,904	689,172	826,122	713,658	712,800	712,800	686,400	712,800	686,400	712,800	8,579,208
Archbald (C)	205,326	1,135,794	685,146	637,626	663,036	705,474	400,000	400,000	400,000	400,000	400,000	400,000	6,432,402
Frackville Energy	2,042,204	1,993,609	1,864,650	1,998,103	1,925,984	1,808,200	1,927,200	1,927,200	1,861,200	1,927,200	1,861,200	1,927,200	23,063,950
Continental (D)	601,965	240,625	1,347,500	1,347,500	1,347,500	1,347,500	1,390,800	1,390,800	1,390,800	1,390,800	1,390,800	1,390,800	14,577,390
NEPCO	1,764,176	1,584,850	1,975,580	1,819,228	2,031,414	1,862,322	1,920,600	1,920,600	1,861,200	1,920,600	1,861,200	1,920,600	22,482,370
Schuylkill Energy	3,762,521	3,561,581	3,515,214	3,742,162	4,027,776	3,511,171	3,293,400	3,293,400	3,187,800	3,300,000	3,187,800	3,293,400	41,676,227
Foster Wheeler	1,752,448	1,799,956	1,808,455	1,306,515	1,866,140	1,999,415	1,716,000	1,716,000	1,656,600	1,716,000	1,656,600	1,716,000	20,710,129
Taylor Energy	52,734	57,282	48,216	51,960	55,416	47,904	36,000	36,000	36,000	36,000	36,000	36,000	529,512
Keystone Energy	206,160	229,259	194,400	216,540	223,380	202,320	192,000	192,000	186,000	192,000	186,000	192,000	2,412,059
Total Qualified Facil.	15,101,229	16,040,681	16,679,631	16,495,442	17,787,331	16,765,262	16,186,600	16,186,600	15,687,500	16,199,800	15,215,600	15,699,100	194,044,776
Total Purch. & Int'chnge	$ 14,693,241	$ 20,863,155	$ 29,117,893	$23,835,075	$ 19,462,249	$ 3,023,247	$ 8,722,000	$ 8,351,500	$ 8,108,600	$ 11,852,900	$ 19,596,000	$ 20,548,600	$188,174,460

* Six months actual, six months estimate

(A) Cost of Safe Harbor and the non-energy portion of Borderline purchases, which are not included in the ECR.

(B) Pursuant to a settlement agreement approved by the Commission at Docket No. P-00950915, the power purchase agreement with Paxton Creek was revised as of January 1, 1996. Payments to Paxton now include both a fixed and variable cost component. Fixed costs are recorded on a one-month lag basis and variable costs are recorded on a two-month lag basis.

(C) PP&L's budget reflects the buyout of the Archbald contract. PP&L's actual books will reflect this beginning in July 1997 with the first of 49 monthly payments.

(D) PP&L bought out the Continental contract, which is being paid in five annual installments. The first installment of $16,170,000 was paid in February and is being allocated throughout the year.

Pennsylvania Power & Light Company
Detailed Summary of Actual Purchased Power and Interchange
Mills per KWH
For the Year 1997*

	ACTUAL						ESTIMATED						
	January	February	March	April	May	June	July	August	September	October	November	December	Average
Purchased Power:													
Other Utilities													
Energy Cost	26.72	25.24	19.35	22.90	19.98	21.94	21.24	20.18	22.19	20.06	17.05	19.11	21.57
Demand Cost													
Total Cost	28.17	27.09	21.32	25.68	21.60	23.03	24.95	22.84	24.67	22.63	19.08	21.35	23.52
Interchange Power:													
Receipts - PJM	29.73	22.36	21.48	24.89	28.27	38.64	25.40	23.20	25.30	23.00	19.30	21.70	24.70
Deliveries													
PJM	43.87	23.59	20.63	17.28	15.10	22.26	21.30	20.10	21.20	19.92	17.70	19.50	20.94
Other Utilities	23.57	18.77	18.56	20.00	17.61	20.03	20.90	19.89	20.82	19.78	18.96	19.20	19.99
Net Interchange Power	22.50	17.28	15.81	18.06	16.20	19.95	20.86	19.89	20.83	19.68	18.55	18.59	19.25
Qualified Facilities													
Hammermill	37.34	38.22	38.25	37.51	38.59	37.82	39.00	39.00	39.00	39.00	0.00	0.00	38.38
Windmills, Hydro & Other	60.00	60.01	59.99	59.99	60.01	60.00	54.00	54.00	54.00	54.00	54.00	54.00	58.13
Paxton Creek (A)	18.54	226.52	75539.50	398.18	228.21	34.87	83.30	83.30	73.75	83.30	73.75	75.73	85.11
Harrisburg Steam	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00
Gilberton	65.98	65.97	65.92	65.97	65.97	65.95	66.00	66.00	66.00	66.00	66.00	66.00	65.98
Koppers	59.93	59.52	59.40	59.72	59.91	59.91	58.00	58.00	58.00	58.00	58.00	58.00	58.87
Viking Energy	66.00	66.00	66.00	66.00	66.00	66.00	65.39	65.39	66.00	65.39	66.00	66.00	65.85
Archbald (B)	66.00	66.00	66.00	66.00	66.00	66.00	0.00	0.00	0.00	0.00	0.00	0.00	105.28
Frackville Energy	65.36	65.62	65.43	65.58	65.44	65.43	66.00	66.00	66.00	66.00	66.00	66.00	65.74
Continental (C)	52.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,268.37
NEPCO	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00
Schuylkill Energy	65.25	65.17	65.18	65.15	64.96	65.12	66.00	66.00	66.00	66.00	66.00	66.00	65.54
Foster Wheeler	64.81	64.48	63.51	64.26	64.53	64.10	66.00	66.00	66.00	66.00	66.00	66.00	65.11
Taylor Energy	59.99	59.98	59.97	60.00	59.97	60.03	60.00	60.00	60.00	60.00	60.00	60.00	59.99
Keystone Energy	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00
Total Qualified Facil.	62.79	65.02	70.09	69.86	69.18	68.75	72.16	72.16	72.43	72.16	74.40	74.12	70.10
Total Purch. & Int'chnge	212.49	87.74	39.61	59.83	171.29	-5.60	-55.66	-44.80	-48.29	-551.30	45.49	49.88	142.08

* Six months actual, six months estimate

(A) Pursuant to a settlement agreement approved by the Commission at Docket No. P-00950915, the power purchase agreement with Paxton Creek was revised as of January 1, 1996. Payments to Paxton now include both a fixed and variable cost component. Because payments for monthly fixed costs are made regardless of use and differences associated with the timing of when costs and mwh are recorded on the Company's books, a monthly mills/kwh calculation is not a relevant measure of the cost of output related to this agreement.

(B) PP&L's budget reflects the buyout of the Archbald contract. PP&L's actual books will reflect this beginning in July 1997 with the first of 49 monthly payments.

(C) PP&L bought out the Continental contract, which is being paid in five annual installments. The first installment of $16,170,000 was paid in February and is being allocated throughout the year.

Pennsylvania P[illegible] Light Company
Summary of Ac[illegible]t of Generation
For th[illegible] 1997*

Cumulative: January-December 1997

	Coal			Oil #6			Oil #2			Natural Gas			Nuclear	Total Fuel Cost Per KWH Generated		
Generating Station	Tons Burned	Total Cost	Unit Cost ($/Ton)	Barrels Burned	Total Cost	Unit Cost ($/Bbl.)	Gallons Burned	Total Cost	Unit Cost ($/Gal.)	mmBTU Burned	Total Cost	Unit Cost ($/mmBTU)	Total Cost	Net Generation (MWH)	Total Fuel Cost	Mills Per KWH
Nuclear Fueled																
Susquehanna 1													$ 30,869,701	7,753,340	$ 30,869,701	3.98
Susquehanna 2													26,713,233	6,732,425	26,713,233	3.97
Total													57,582,934	14,485,765	57,582,934	3.98
Fossil Fueled																
Brunner Island	3,067,337	$ 121,111,672	39.48				2,165,459	$ 1,258,071	0.58					8,037,055	122,369,743	15.23
Martins Creek 1 & 2	625,333	21,193,074	33.89				1,238,554	677,978	0.55					1,453,278	21,871,052	15.05
Sunbury	1,292,436	32,798,223	25.38				430,021	248,242	0.58					2,236,321	33,046,465	14.78
Holtwood 17	337,491	5,797,785	17.18				78,691	52,242	0.66					479,303	5,850,027	12.21
Keystone	587,786	19,832,490	-				227,967	126,830	0.56					1,552,953	19,959,320	12.85
Conemaugh	516,145	15,729,962	30.48				65,166	35,398	0.54	7,094	$ 25,970	3.66		1,380,777	15,791,330	11.44
Montour	3,262,754	119,091,172	36.50				3,641,577	2,268,410	0.62					8,369,459	121,359,582	14.50
Martins Creek 3 & 4 (excl. Sun Oil Adj.)				599,783	$ 11,477,730	-	1,691,863	985,324	0.58	5,975,106	14,589,234	2.44		792,648	27,052,288	34.13
Fuel Oil Litigation Settlement		(444,925)													(444,925)	
Total	9,689,282	335,109,453	34.59	599,783	11,477,730	-	9,539,298	5,652,495	0.59	5,982,200	14,615,204	2.44		24,301,794	366,854,882	15.10
Internal Combustion																
Combustion Turbines							1,084,270	606,020	0.56					12,943	606,020	46.82
Diesels							87,129	51,697	0.59					1,163	51,697	44.45
Total							1,171,399	657,717	0.56					14,106	657,717	46.63
Hydro																
Holtwood														573,846		
Wallenpaupack														74,608		
Total														648,454		
Total Fuel and Cost	9,689,282	$ 335,109,453	34.59	599,783	$ 11,477,730	-	10,710,697	$ 6,310,212	0.59	5,982,200	$14,615,204	2.44	$ 57,582,934	39,450,119	$ 425,095,533	10.78

* Six months actual, six months estimate

Exhibit JMK 6
Page 9 of 33

Pennsylvania P[illegible] & Light Company
Detailed Summary of Actual Gene[illegible]nd Costs (Steam and Hydro Stations)
MW[illegible]eration
For the Year 1997*

Generating Station	ACTUAL						ESTIMATED						
	January	February	March	April	May	June	July	August	September	October	November	December	Total
Nuclear Fueled													
Susquehanna 1	742,837	591,494	310,340	720,875	741,451	711,743	662,900	662,900	641,500	662,900	641,500	662,900	7,753,340
Susquehanna 2	731,030	629,262	290,615	(7,479)	445,306	709,091	662,900	662,900	641,500	662,900	641,500	662,900	6,732,425
Total	1,473,867	1,220,756	600,955	713,396	1,186,757	1,420,834	1,325,800	1,325,800	1,283,000	1,325,800	1,283,000	1,325,800	14,485,765
Fossil Fueled													
Brunner Island	792,673	603,353	708,478	815,617	501,722	719,212	703,800	713,800	587,900	575,800	595,200	719,500	8,037,055
Martins Creek 1 & 2	145,014	123,310	149,638	150,975	151,062	141,079	108,300	108,100	76,500	91,800	89,400	118,100	1,453,278
Sunbury	211,967	181,325	190,101	200,558	148,084	209,986	186,600	187,900	183,500	184,500	159,600	194,200	2,238,321
Holtwood 17	44,751	40,931	41,620	46,790	19,204	29,307	47,000	47,000	45,400	47,000	22,700	47,600	479,303
Keystone	152,128	136,095	75,857	113,945	131,539	142,789	134,900	134,900	130,600	134,700	130,600	134,900	1,552,953
Conemaugh	132,138	116,777	129,137	132,587	89,184	126,354	125,300	125,300	70,700	86,800	121,200	125,300	1,380,777
Montour	769,752	646,565	605,412	386,277	559,954	860,399	797,700	797,500	783,200	829,300	536,300	797,100	8,369,459
Martins Creek 3 & 4	127,258	(2,643) (A)	(3,815) (A)	(25) (A)	4,786	139,087	200,300	190,000	101,100	1,000	6,400	29,200	792,648
Total	2,375,681	1,845,713	1,896,428	1,846,724	1,603,535	2,368,213	2,303,900	2,304,500	1,978,900	1,950,900	1,661,400	2,165,900	24,301,794
Hydro													
Holtwood	50,447	55,370	67,742	60,049	63,707	51,231	36,800	28,800	25,300	31,900	46,800	55,700	573,846
Wallenpaupack	14,275	6,901	11,030	2,863	509	4,730	6,300	5,700	5,900	5,100	4,700	6,600	74,608
Total	64,722	62,271	78,772	62,912	64,216	55,961	43,100	34,500	31,200	37,000	51,500	62,300	648,454
Internal Combustion													
Combustion Turbines	175	15	314	17	155	2,667	5,000	1,600	2,400	200	200	200	12,943
Diesels	66	83	80	121	102	111	100	100	100	100	100	100	1,163
Total	241	98	394	138	257	2,778	5,100	1,700	2,500	300	300	300	14,106
Total Steam & Hydro Generation	3,914,270	3,128,740	2,576,155	2,623,032	2,854,508	3,845,008	3,672,800	3,664,600	3,293,100	3,313,700	2,995,900	3,554,000	39,436,013

* *Six months actual, six months estimate*
(A) Oil/Gas Generation was not being used due to the mild weather.

Pennsylvania P[illegible] Light Company
Detailed Summary of Actual G[illegible]n and Costs (Steam Stations)
F[illegible]ts
For the Year 1997*

	ACTUAL						ESTIMATED						
Generating Station	January	February	March	April	May	June	July	August	September	October	November	December	Total
Nuclear													
Susquehanna 1	$ 2,900,934	$ 2,320,559	$ 1,245,593	$ 2,816,825	$ 2,906,927	$ 2,817,863	$ 2,672,000	$ 2,672,000	$ 2,585,000	$ 2,675,000	$ 2,585,000	$ 2,672,000	$ 30,869,701
Susquehanna 2	2,743,023	2,538,606	1,201,744	-	1,792,882	2,836,978	2,628,000	2,628,000	2,542,000	2,632,000	2,542,000	2,628,000	26,713,233
D & D Expense	231,190	231,190	231,190	231,190	231,190	231,190	266,000	266,000	266,000	266,000	266,000	266,000	2,983,140
Spent Fuel	1,373,153	1,137,337	560,720	667,120	1,107,640	1,326,116	1,234,000	1,234,000	1,194,000	1,236,000	1,194,000	1,234,000	13,498,086
Total	7,248,300	6,227,692	3,239,247	3,715,135	6,038,639	7,212,147	6,800,000	6,800,000	6,587,000	6,809,000	6,587,000	6,800,000	74,064,160
Coal													
Brunner Island	11,746,586	9,117,965	10,526,041	12,276,552	7,563,875	10,911,851	10,672,100	10,793,400	8,940,800	8,705,300	8,976,600	10,874,600	121,111,672
Martins Creek 1 & 2	1,961,705	1,871,518	2,252,861	2,171,827	2,109,397	1,975,646	1,637,800	1,633,700	1,131,100	1,362,400	1,327,700	1,757,400	21,193,074
Sunbury	3,134,983	2,732,304	2,859,567	2,986,791	2,096,847	3,092,231	2,721,300	2,723,800	2,673,800	2,678,500	2,314,900	2,763,200	32,798,223
Holtwood 17	593,740	526,008	523,635	500,163	239,903	332,736	565,800	566,000	538,700	565,800	282,100	563,200	5,797,785
Keystone	1,953,048	1,727,226	984,195	1,435,378	1,630,888	1,789,655	1,693,200	1,729,200	1,702,700	1,736,600	1,704,100	1,746,300	19,632,490
Conemaugh (excl. Limestone)	1,531,879	1,356,268	1,498,725	1,547,050	1,049,556	1,458,384	1,393,600	1,394,200	796,600	975,100	1,334,500	1,394,100	15,729,962
Montour	11,325,193	9,763,643	8,313,545	5,320,236	7,921,124	11,921,131	11,333,200	11,332,800	11,114,900	11,801,100	7,612,700	11,331,600	119,091,172
Fuel Oil Litigation Settlement						(444,925)							(444,925)
Total	32,247,136	27,094,932	26,960,569	26,239,997	22,811,590	31,036,709	30,017,000	30,173,100	26,898,600	27,824,800	23,554,600	30,450,400	335,109,453
Oil #6													
Martins Creek 3 & 4	4,384,607	167,130	8,291	100,575	326,270	3,540,557	898,100	614,900	428,500	-	-	1,008,800	11,477,730
Oil #2													
Brunner Island	136,899	68,615	125,170	11,294	136,043	67,650	111,300	95,800	103,700	52,100	97,100	252,400	1,258,071
Martins Creek 1 & 2	67,630	31,924	30,174	18,971	16,501	60,278	84,500	74,700	47,500	70,900	84,500	90,400	677,978
Sunbury	25,649	17,916	31,910	11,814	13,514	27,539	10,100	20,800	20,600	19,400	29,300	19,700	248,242
Holtwood 17	16,396	1,746	8,716	4,126	436	7,918	2,200	2,100	1,100	1,600	4,800	1,100	52,242
Keystone	4,054	1,167	-	30,234	13,903	972	12,700	12,500	12,600	12,700	12,900	13,100	126,830
Conemaugh	895	-	2,411	360	4,032	-	4,600	4,600	4,600	4,600	4,600	4,700	35,398
Montour	297,370	199,417	406,195	108,696	423,733	148,399	109,600	56,200	75,100	143,700	114,100	185,900	2,268,410
Martins Creek 3 & 4	263,460	4,722	16,312	9,660	41,900	41,470	191,200	124,500	48,600	35,800	96,200	111,500	985,324
Total	812,353	325,509	620,888	195,155	650,064	354,226	526,200	391,200	313,800	340,800	443,500	678,800	5,652,495
Natural Gas													
Martins Creek	289,149	147,800	59,822	54,644	-	1,621,519	4,707,400	4,796,000	2,662,800	19,600	230,500	-	14,589,234
Conemaugh	4,971	705	4,284	246	15,945	(181)	(A)	(A)	(A)	(A)	(A)	(A)	25,970
Total	294,120	148,505	64,106	54,890	15,945	1,621,338	4,707,400	4,796,000	2,662,800	19,600	230,500	-	14,615,204
Internal Combustion													
Combustion Turbines	13,796	1,144	22,941	1,580	22,992	184,567	162,000	96,000	78,000	6,000	6,000	11,000	606,020
Diesels	3,384	4,542	4,190	5,770	4,655	5,156	4,000	4,000	4,000	4,000	4,000	4,000	51,697
Total	17,180	5,686	27,131	7,350	27,647	189,723	166,000	100,000	82,000	10,000	10,000	15,000	657,717
Total Steam Station Generation	$44,986,516	$ 33,963,768	$ 30,893,121	$ 30,305,752	$29,642,508	$43,764,977	$42,946,700	$42,775,200	$36,890,700	$34,994,200	$30,815,600	$38,938,000	$ 440,919,042

* Six months actual, six months estimate
(A) Conemaugh Natural Gas figures are not broken out in the budget. They are included in Conemaugh Coal figures.

Exhibit JMK 6
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Pennsylvania Po[illegible]& Light Company
Detailed Summary of Actual G[illegible]n and Costs (Steam Stations)
Mills[illegible]WH
For the Year 1997*

Generating Station	ACTUAL						ESTIMATED						
	January	February	March	April	May	June **	July	August	September	October	November	December	Average
Nuclear Fueled													
Susquehanna 1	3.91	3.92	4.01	3.91	3.92	3.96	4.03	4.03	4.03	4.04	4.03	4.03	3.98
Susquehanna 2	3.75	4.03	4.14	0.00	4.03	4.00	3.96	3.96	3.96	3.97	3.96	3.96	3.97
Average (A)	3.83	3.98	4.07	3.95	3.96	3.98	4.00	4.00	4.00	4.00	4.00	4.00	3.98
Fossil Fueled													
Brunner Island	14.99	15.23	15.04	15.07	15.35	15.27	15.32	15.26	15.38	15.21	15.25	15.46	15.23
Martins Creek 1 & 2	13.99	15.44	15.26	14.51	14.07	14.43	15.90	15.80	15.41	15.61	15.80	15.65	15.05
Sunbury	14.91	15.17	15.21	14.95	14.45	14.86	14.64	14.61	14.68	14.62	14.69	14.43	14.78
Holtwood 17	13.63	12.89	12.79	10.78	12.52	11.62	12.09	12.09	11.89	12.07	12.64	11.86	12.21
Keystone	12.86	12.70	12.97	12.86	12.50	12.54	12.65	12.91	13.13	12.99	13.15	13.04	12.85
Conemaugh (excl Limestone)	11.64	11.62	11.66	11.67	11.99	11.54	(D)	(D)	(D)	(D)	(D)	(D)	11.44
Montour	15.10	15.41	14.40	14.05	14.90	14.03	14.34	14.28	14.29	14.40	14.41	14.45	14.50
Martins Creek 3 & 4	38.80	-120.94 (B)	-22.13 (B)	-6595.16 (B)	76.93	37.41	28.94	29.13	31.06	55.40	51.05	38.37	34.13
Average	15.89	15.03	14.58	14.40	14.72	15.43	15.69	15.61	15.31	14.45	14.58	14.84	15.10
Internal Combustion													
Combustion Turbines	78.83	76.27	73.06	92.94	148.34 (C)	69.20	32.40	60.00	32.50	30.00	30.00	55.00	46.82
Diesels	51.27	54.72	52.38	47.69	45.64	46.45	40.00	40.00	40.00	40.00	40.00	40.00	44.45
Average	71.29	58.02	68.86	53.26	107.58	68.29	32.55	58.82	32.80	33.33	33.33	50.00	46.63
Steam Station Generation Average	11.49	10.86	11.99	11.55	10.38	11.38	11.69	11.67	11.20	10.56	10.29	10.96	11.18

* Six months actual, six months estimate

** The effects of the Fuel Oil Litigation Settlement are not included for individual plants, but are reflected in the averages.

(A) Excludes D&D expense and Spent Nuclear Fuel costs.

(B) Martins Creek natural gas fuel costs include adjustments from previous months. This along with negative generation for February through April caused the mills/kwh to be lower that previous months.

(C) Many of the CTs were not running in April. More fuel was used and lower generation produced in May to start them up again, causing a variance in mills/KWH.

(D) Conemaugh Natural Gas figures are not broken out in the budget. They are included in Conemaugh Coal figures.

Pennsylvania [illegible] & Light Company
Detailed Summary of Actual Gener[illegible] Costs (Fossil-fueled Steam Stations)
Units of [illegible] Consumed
For the Year 1997*

Generating Station	ACTUAL						ESTIMATED						
	January	February	March	April	May	June	July	August	September	October	November	December	Total
Coal (Tons)													
Brunner Island	300,568	232,749	266,354	307,845	190,781	272,040	271,000	274,000	227,000	221,000	228,000	276,000	3,067,337
Martins Creek 1 & 2	56,483	52,642	62,443	59,240	69,512	59,033	49,000	49,000	34,000	41,000	40,000	53,000	625,333
Sunbury	124,987	109,441	111,985	121,057	92,550	116,416	105,000	106,000	104,000	102,000	89,000	110,000	1,292,436
Holtwood 17	32,317	27,727	28,502	30,069	13,898	19,978	34,000	34,000	32,000	34,000	17,000	34,000	337,491
Keystone	57,800	50,726	28,778	42,860	49,242	54,380	51,000	51,000	50,000	51,000	50,000	51,000	587,786
Conemaugh	49,898	44,497	48,597	50,196	34,570	48,387	46,000	46,000	26,000	32,000	44,000	46,000	516,145
Montour	306,762	261,664	224,701	144,083	215,207	322,137	314,000	314,000	308,000	327,000	211,000	314,000	3,262,754
Total	928,795	779,646	771,360	755,350	665,760	892,371	870,000	874,000	781,000	808,000	679,000	884,000	9,689,282
Oil #6 (Barrels)													
Martins Creek 3 & 4	227,382	8,652	429	5,204	16,882	183,234	48,000	33,000	23,000	-	-	54,000	599,783
Oil #2 (Gallons)													
Brunner Island	177,330	90,082	178,330	16,697	212,468	108,552	223,000	194,000	206,000	102,000	186,000	471,000	2,165,459
Martins Creek 1 & 2	107,428	49,795	48,601	29,623	26,453	98,654	169,000	152,000	94,000	137,000	160,000	168,000	1,238,554
Sunbury	33,616	24,087	45,340	19,664	23,287	49,827	20,000	42,000	41,000	38,000	56,000	37,000	430,021
Holtwood 17	21,633	2,331	12,058	5,881	623	12,165	4,000	4,000	2,000	3,000	9,000	2,000	78,691
Keystone	5,792	1,667	-	47,241	21,723	1,544	25,000	25,000	25,000	25,000	25,000	25,000	227,967
Conemaugh	1,278	-	3,444	514	5,390	540	9,000	9,000	9,000	9,000	9,000	9,000	65,166
Montour	379,202	261,427	575,999	167,974	680,587	248,388	217,000	112,000	149,000	281,000	220,000	351,000	3,641,577
Martins Creek 3 & 4	406,198	7,279	25,130	16,233	70,409	68,614	342,000	225,000	88,000	65,000	175,000	203,000	1,691,863
Total	1,132,677	436,668	886,902	303,827	1,040,940	586,284	1,009,000	763,000	614,000	660,000	840,000	1,266,000	9,539,296
Natural Gas (mmBTU)													
Martins Creek	40,100	9,439	8,300	5,800	-	534,467	2,104,000	2,079,000	1,099,000	8,000	87,000	-	5,975,106
Conemaugh	1,297	134	1,110	9	4,659	(115)	(A)	(A)	(A)	(A)	(A)	(A)	7,094
Total	41,397	9,573	9,410	5,809	4,659	534,352	2,104,000	2,079,000	1,099,000	8,000	87,000	-	5,982,200
Internal Combustion (Gallons)													
Combustion Turbines	21,884	1,780	36,662	2,467	38,432	306,375	303,506	181,440	148,390	11,400	11,400	20,533	1,084,270
Diesels	4,673	6,362	6,029	8,892	7,330	8,513	7,494	7,560	7,610	7,600	7,600	7,467	87,129
Total	26,557	8,142	42,691	11,359	45,762	314,888	311,000	189,000	156,000	19,000	19,000	28,000	1,171,399

* Six months actual, six months estimate

(A) Conemaugh Natural Gas figures are not broken out in the budget. They are included in Conemaugh Coal figures.

Pennsylvania Power & Light Company
Detailed Summary of Actual Generation Costs (Fossil-fueled Steam Stations)
Cost Per Unit of Fuel Consumed
For the Year 1997*

Generating Station	ACTUAL						ESTIMATED						
	January	February	March	April	May	June **	July	August	September	October	November	December	Average
Coal ($/Ton)													
Brunner Island	$39.08	$39.18	$39.53	$39.89	$39.65	$40.11	$39.38	$39.39	$39.39	$39.39	$39.38	$39.40	$39.48
Martins Creek 1 & 2	34.74	35.55	36.08	36.66	30.35	33.47	33.42	33.34	33.27	33.23	33.19	33.16	33.89
Sunbury	25.08	24.97	25.54	24.67	22.66	26.56	25.92	25.70	25.71	26.28	26.01	25.30	25.38
Holtwood 17	18.37	18.97	18.37	16.63	17.26	16.66	16.64	16.65	16.63	16.64	16.59	16.56	17.18
Keystone	33.79	34.05	34.20	33.49	33.12	32.91	33.20	33.91	34.05	34.05	34.08	34.24	33.74
Conemaugh	30.70	30.48	30.84	30.82	30.38	30.14	30.30	30.31	30.64	30.47	30.33	30.31	30.48
Montour	36.92	37.29	37.00	38.92	36.81	37.01	36.09	36.09	36.09	36.09	36.08	36.09	36.50
Average	$34.72	$34.75	$34.95	$34.74	$33.96	$34.78	$34.50	$34.52	$34.44	$34.44	$34.69	$34.45	$34.59
Oil #6 ($/Barrel)													
Martins Creek 3 & 4 (excl. Sun Oil Adj)	$19.28	$19.32	$19.33	$19.33	$19.33	$19.32	$18.71	$18.63	$18.63	$0.00	$0.00	$18.68	$19.14
Oil #2 ($/Gallon)													
Brunner Island	$0.77	$0.76	$0.70	$0.68	$0.64	$0.62	$0.50	$0.49	$0.50	$0.51	$0.52	$0.54	$0.58
Martins Creek 1 & 2	0.63	0.64	0.65	0.64	0.62	0.61	0.50	0.49	0.51	0.52	0.53	0.54	0.55
Sunbury	0.76	0.74	0.70	0.60	0.58	0.55	0.51	0.50	0.50	0.51	0.52	0.53	0.58
Holtwood 17	0.76	0.75	0.72	0.70	0.70	0.65	0.55	0.53	0.55	0.53	0.53	0.55	0.66
Keystone	0.70	0.70	-	0.64	0.64	0.63	0.51	0.50	0.50	0.51	0.52	0.52	0.56
Conemaugh	0.70	-	0.70	0.70	0.75	-	0.51	0.51	0.51	0.51	0.51	0.52	0.54
Montour	0.78	0.76	0.71	0.65	0.62	0.60	0.51	0.50	0.50	0.51	0.52	0.53	0.62
Martins Creek 3 & 4	0.65	0.65	0.65	0.60	0.60	0.60	0.56	0.55	0.55	0.55	0.55	0.55	0.58
Average	$0.72	$0.75	$0.70	$0.64	$0.62	$0.60	$0.52	$0.51	$0.51	$0.52	$0.53	$0.54	$0.59
Natural Gas ($/mmBTU)													
Martins Creek	7.21	15.66 (A)	$7.21	$9.42	$0.00	$3.03	$2.24	$2.31	$2.42	$2.45	$2.65	$0.00	$2.44
Conemaugh	3.83	5.27	3.86	26.54 (B)	3.42	1.57	(C)	(C)	(C)	(C)	(C)	(C)	3.66
Average	$7.10	$15.51	$6.81	$9.45	$3.42	$3.03	$2.24	$2.31	$2.42	$2.45	$2.65	#DIV/0!	$2.44
Internal Combustion ($/Gallon)													
Combustion Turbines	$0.63	$0.64	$0.63	$0.64	$0.60	$0.60	$0.53	$0.53	$0.53	$0.53	$0.53	$0.54	$0.56
Diesels	0.72	0.71	0.69	0.65	0.64	0.61	0.53	0.53	0.53	0.53	0.53	0.54	0.59
Average	$0.65	$0.70	$0.64	$0.65	$0.60	$0.60	$0.53	$0.53	$0.53	$0.53	$0.53	$0.54	$0.56

* Six months actual, six months estimate
** The effects of the Fuel Oil Litigation Settlement are not included for individual plants, but are reflected in the averages.
(A) Martins Creek natural gas fuel costs include adjustments from previous months.
(B) Higher than normal because there is a fixed charge of $1800 for every order and this time it's being spread over a lower volume than normal.
(C) Conemaugh Natural Gas figures are not broken out in the budget. They are included in Conemaugh Coal figures.

Pennsylvania Power & Light Company
Detailed Summary of Actual Energy Costs
For the Twelve Months Ended December 31, 1998

	MWH	Cost in thousands	Mill/KWH
Generation			
Nuclear (Includes D&D and Spent Fuel Expense)	13,530,000	$ 71,293	5.27
Coal (Includes Retired Miners Health Care)	23,676,000	349,844	14.78
Oil (incl. Sun Oil Adj.)	610,000	15,647	25.65
CTs and Diesels	1,750	99	56.57
Hydro	672,000	-	0.00
Emission Allowances Consumed	0	2,243	N/A
Total Generation	38,489,750	439,126	11.41
Purchased Power			
Other Utilities	3,310,000	74,520	22.51
Qualified Facilities (a)	2,576,613	188,052	72.98
Total Purchased Power	5,886,613	262,572	44.60
Less Off System Sales			
Interchange - PJM	961,000 (a)	10,291 (a)	10.71
Other Utilities	2,181,000	48,977	22.46
Atlantic Electric	138,000	2,071	15.01
Jersey Central Power & Light	3,286,000	33,016	10.05
Baltimore Gas & Electric	893,000	4,704	5.27
Total Off System Sales	7,459,000	99,059	13.28
System Cost of Power	36,917,363	602,639	16.32
Less Adjustments			
Safe Harbor		10,098	
Borderline/Waste Heat		126	
Price Response Service Adjustment (A)		4,013	
Energy Savings Associated with Phase Out of Expiring Bulk Power Agreement		(22,052)	
Total Adjustments		(7,815)	
Cost of Energy - "Fc"		$ 610,454	17.91
Net Energy Available	36,917,363		
Less: Line Losses	2,511,251		
Net Unbilled Sales	(18,100)		
Company Use	128,260		
Price Response Service Adjustment	215,354		
Actual Sales - "St"	34,080,598		
Line Loss Percentage	6.8%		
Retail Sales	32,900,730		

(a) PJM purchases and sales are shown as a net amount.

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Net System MWH Requirements
Computation Period: January 1, 1998 - December 31, 1998

Generation	Total
Nuclear	13,530,000
Coal	23,676,000
Oil/Gas	610,000
Internal Combustion	1,750
Hydro	672,000
Total Generation	38,489,750
Purchased Power	
Other Utilities	3,310,000
Qualified Facilities (Details on 3A page 4 of 4)	2,576,613
Total Purchased Power	5,886,613
Off-system Sales	
PJM Interchange Sales	(961,000)
Other Utilities	(2,181,000)
Atlantic Electric	(138,000)
Jersey Central	(1,721,000)
Jersey Central	(1,565,000)
BG&E	(893,000)
Total Off-system Sales	(7,459,000)
Net Energy Available	36,917,363
Less: Line Losses	2,511,251
Company Use	128,260
Net Unbilled Sales	(18,100)
Projected Sales - "St"	34,295,952
Line Loss Percentage	6.8

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Net System MWH Requirements (Excluding Effect of Expiring Bulk Power Agreements)
Computation Period: January 1, 1998 - December 31, 1998

Generation	Total
Nuclear	13,530,000
Coal	23,676,000
Oil/Gas	610,000
Internal Combustion	1,750
Hydro	672,000
Total Generation	38,489,750
Purchased Power	
Other Utilities	3,310,000
Qualified Facilities (Details on 3A page 4 of 4)	2,576,613
Total Purchased Power	5,886,613
Off-system Sales	
PJM Interchange Sales	619,000
Other Utilities	(2,181,000)
Atlantic Electric	(712,000)
Jersey Central	(4,292,000)
Jersey Central	0
BG&E	(893,000)
Total Off-system Sales	(7,459,000)
Net Energy Available	36,917,363
Less: Line Losses	2,511,251
Company Use	128,260
Net Unbilled Sales	(18,100)
Projected Sales - "St"	34,295,952
Line Loss Percentage	6.8

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Net System MWH Requirements (Effect of Expiring Bulk Power Agreements)
Computation Period: January 1, 1998 - December 31, 1998

Generation	Total
Nuclear	0
Coal	0
Oil/Gas	0
Internal Combustion	0
Hydro	0
Total Generation	0
Purchased Power	
Other Utilities	0
Qualified Facilities (Details on 3A page 4 of 4)	0
Total Purchased Power	0
Off-system Sales	
PJM Interchange Sales	(1,580,000)
Other Utilities	0
Atlantic Electric	574,000
Jersey Central	2,571,000
Jersey Central	(1,565,000)
BG&E	0
Total Off-system Sales	0
Net Energy Available	0
Less: Line Losses and	0
Company Use	0
Net Unbilled Sales	0
Projected Sales - "St"	0
Line Loss Percentage	0

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Net System MWH Requirements
Computation Period: January 1, 1998 - December 31, 1998

Generation From Qualified Facilities	Total MWH
Hammermill	0
Bethlehem Steel	0
Windmill, Hydro & Other	16,667
Paxton Creek	10,800
Harrisburg Steam	31,676
Gilberton	637,728
Koppers	50,786
Viking Energy	124,786
Archbald	0
Frackville Energy	342,166
Continental	0
NEPCO	350,400
Schuylkill Energy	584,993
Mt. Carmel	304,848
Taylor Energy	11,000
Keystone	26,667
West Allegheny	84,096
Total Qualified Facilities	2,576,613

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Net System Costs - Dollars
Computation Period - January 1, 1998 - December 31, 1998

Generation Cost	Total
Nuclear (Incl. Spent Fuel & D&D)	71,293,000
Coal (Excl. Miner's Health Care)	347,392,000
Conemaugh Scrubber Costs	819,600
Oil/Gas (Incl. Sun Oil Adj.)	15,647,000
Internal Combustion	99,000
Total Generation	435,250,600
Purchased Power	
Other Utilities	73,924,000
Qualified Facilities	188,052,000
Total Purchased Power	261,976,000
Off-system Sales	
PJM Interchange Sales	(10,291,000)
Other Utilities	(49,573,000)
Atlantic Electric	(2,071,000)
Jersey Central	(16,272,000)
Jersey Central	(16,744,000)
BG&E	(4,704,000)
Total Off-system Sales	(99,655,000)
System Cost Of Power	597,571,600
Total EHV Charges	1,191,500
Less Adjustments: Sun Oil Adjustment	0
Safe Harbor	10,098,000
Borderline/Waste Heat	126,000
Installed Capacity Payments	0
Sale of Emission Allowances	0
Total Adjustments	10,224,000
Total Energy Cost - "Fc"	588,539,100

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Net System Costs - Dollars (Excluding Effect of Expiring Bulk Power Agreements)
Computation Period - January 1, 1998 - December 31, 1998

Generation Cost	Total
Nuclear (Incl. Spent Fuel & D&D)	71,293,000
Coal (Excl. Miner's Health Care)	347,392,000
Conemaugh Scrubber Costs	819,600
Oil/Gas (Incl. Sun Oil Adj.)	15,647,000
Internal Combustion	99,000
Total Generation	435,250,600
Purchased Power	
Other Utilities	73,924,000
Qualified Facilities	188,052,000
Total Purchased Power	261,976,000
Off-system Sales	
PJM Interchange Sales	28,905,000
Other Utilities	(49,573,000)
Atlantic Electric	(10,675,000)
Jersey Central	(41,556,000)
Jersey Central	0
BG&E	(4,704,000)
Total Off-system Sales	(77,603,000)
System Cost Of Power	619,623,600
Total EHV Charges	1,191,500
Less Adjustments: Sun Oil Adjustment	0
Safe Harbor	10,098,000
Borderline/Waste Heat	126,000
Installed Capacity Payments	0
Sale of Emission Allowances	0
Total Adjustments	10,224,000
Total Energy Cost - "Fc"	610,591,100

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Net System Costs - Dollars (Effect of Expiring Bulk Power Agreements)
Computation Period - January 1, 1998 - December 31, 1998

Generation Cost	Total
Nuclear (Incl. Spent Fuel & D&D)	0
Coal (Excl. Miner's Health Care)	0
Conemaugh Scrubber Costs	0
Oil/Gas (Incl. Sun Oil Adj.)	0
Internal Combustion	0
Total Generation	0
Purchased Power	
Other Utilities	0
Qualified Facilities	0
Total Purchased Power	0
Off-system Sales	
PJM Interchange Sales	(39,196,000)
Other Utilities	0
Atlantic Electric	8,604,000
Jersey Central	25,284,000
Jersey Central	(16,744,000)
BG&E	0
Total Off-system Sales	(22,052,000)
System Cost Of Power	(22,052,000)
Total EHV Charges	0
Less Adjustments: Sun Oil Adjustment	0
Safe Harbor	0
Borderline/Waste Heat	0
Installed Capacity Payments	0
Sale of Emission Allowances	0
Total Adjustments	0
Total Energy Cost - "Fc"	(22,052,000)

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Net System Costs - Dollars
Computation Period: January 1, 1998 - December 31, 1998

Generation From Qualified Facilities	Total $
Hammermill	0
Bethlehem Steel	0
Windmill, Hydro & Other	1,000,000
Paxton Creek	875,000
Harrisburg Steam	1,901,000
Gilberton	42,090,000
Koppers	3,047,000
Viking Energy	8,236,000
Archbald	4,800,000
Frackville Energy	22,583,000
Continental	16,690,000
NEPCO	23,126,000
Schuylkill Energy	38,610,000
Mt. Carmel	20,120,000
Taylor Energy	660,000
Keystone	1,600,000
West Allegheny	2,271,000
Total Qualified Facilities	187,609,000

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Mills Per KWH
Computation Period: January 1, 1998 - December 31, 1998

Generation	Average
Nuclear (Excl. D&D and Spent Fuel Expenses)	4.0
Coal (Excl. Conemaugh Scrubber)	14.7
Oil/Gas (Excl. Sun Oil Adj.)	25.7
Internal Combustion	56.6
Total Generation (Incl. Hydro)	11.3
Purchased Power	
Other Utilities	22.3
Qualified Facilities (Details on 3C page 4 of 4)	72.8
Total Purchased Power	44.5
Off-system Sales	
PJM Interchange Sales	25.6
Other Utilities	22.7
Atlantic Electric	15.0
Jersey Central	9.5
Jersey Central	10.7
BG&E	5.3
Total Off-system Sales	13.4
Projected Cost Per KWH	17.4

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Mills Per KWH (Excluding Effect of Expiring Bulk Power Agreements)
Computation Period: January 1, 1998 - December 31, 1998

Generation	Average
Nuclear (Excl. D&D and Spent Fuel Expenses)	4.0
Coal (Excl. Conemaugh Scrubber)	14.7
Oil/Gas (Excl. Sun Oil Adj.)	25.7
Internal Combustion	56.6
Total Generation (Incl. Hydro)	11.3
Purchased Power	
Other Utilities	22.3
Qualified Facilities (Details on 3C page 4 of 4)	72.8
Total Purchased Power	44.5
Off-system Sales	
PJM Interchange Sales	28.6
Other Utilities	22.7
Atlantic Electric	15.0
Jersey Central	9.7
Jersey Central	0.0
BG&E	5.3
Total Off-system Sales	10.4
Projected Cost Per KWH	18.1

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Mills Per KWH (Effect of Expiring Bulk Power Agreements)
Computation Period: January 1, 1998 - December 31, 1998

Generation	Average
Nuclear (Excl. D&D and Spent Fuel Expenses)	0.0
Coal (Excl. Conemaugh Scrubber)	0.0
Oil/Gas (Excl. Sun Oil Adj.)	0.0
Internal Combustion	0.0
Total Generation (Incl. Hydro)	0.0
Purchased Power	0.0
Other Utilities	0.0
Qualified Facilities (Details on 3C page 4 of 4)	0.0
Total Purchased Power	0.0
Off-system Sales	
PJM Interchange Sales	-3.0
Other Utilities	0.0
Atlantic Electric	0.0
Jersey Central	-0.2
Jersey Central	10.7
BG&E	0.0
Total Off-system Sales	3.0
Projected Cost Per KWH	-0.6

Pennsylvania Power & Light Company
Detailed Summary of System Projections
Mills Per KWH
Computation Period: January 1, 1998 - December 31, 1998

Generation From Qualified Facilities	Average
Hammermill	0
Bethlehem Steel	0
Windmill, Hydro & Other	60
Paxton Creek	81
Harrisburg Steam	60
Gilberton	66
Koppers	60
Viking Energy	66
Archbald	0
Frackville Energy	66
Continental	0
NEPCO	66
Schuylkill Energy	66
Mt. Carmel	66
Taylor Energy	60
Keystone	60
West Allegheny	27
Total Qualified Facilities	73

Pennsylvania Power & Light Company
Summary of Projected Cost Of Generation
Fuel Quantities And Unit Costs
Computation Period: January 1, 1998 - December 31, 1998

	Coal			#6 Oil			#2 Oil			Natural Gas			Nuclear	Total Fuel Cost Per KWH Generated		
Generating Station	Tons Burned	Total Cost-$	Unit Cost ($/Ton)	Barrels Burned	Total Cost-$	Unit Cost ($/Bbl)	Gallons Burned	Total Cost-$	Unit Cost ($/Gal)	Mcfs Burned	Total Cost-$	Unit Cost ($/Mcf)	Total Cost-$	Net Generation (MWH)	Total Fuel Cost-$	Mills Per KWH
Nuclear Fueled (Excl. D&D and Spent Fuel Expenses)																
Susquehanna 1														6,338,000	26,119,000	4.12
Susquehanna 2														7,191,000	28,146,000	3.91
Total Nuclear Fueled														13,529,000	54,265,000	4.01
Fossil Fueled																
Brunner Island	3,279,330	131,567,000	40.12				2,642,000	1,368,200	0.52					8,250,000	132,935,200	16.11
Martins Creek 1 & 2	531,306	21,208,000	39.92				1,778,000	916,600	0.52					1,200,000	22,124,600	18.44
Sunbury	1,058,340	24,725,000	23.36				454,000	233,900	0.52					1,859,000	24,958,900	13.43
Holtwood 17	394,593	6,647,000	16.85				52,000	27,100	0.52					598,000	6,674,100	11.16
Keystone	536,790	18,666,000	34.77				300,000	154,500	0.52					1,410,000	18,820,500	13.35
Conemaugh (Excl. Scrubber)	508,266	14,994,000	29.50				108,000	55,600	0.51	56,800	195,600	3.44		1,347,000	15,245,200	11.32
Montour	3,359,896	129,586,000	38.57				3,055,000	1,588,300	0.52					9,012,000	131,174,300	14.56
Martins Creek 3 & 4 (Excl. Sun Oil Adj.)				149,490	2,612,000	17.47	2,305,000	1,238,800	0.54	6,644,833	13,035,000	1.96		610,100	16,885,800	27.68
Total Fossil Fueled	9,668,520	347,393,000	35.93	149,490	2,612,000	17.47	10,694,000	5,583,000	0.52	6,701,633	13,230,600	1.97		24,286,100	368,818,600	15.19
Internal Combustion																
Combustion Turbines														1,600		
Diesels														100		
Total Internal Combustion							173,000	95,000	0.55					1,700	95,000	55.88
Hydro																
Holtwood														592,000	0	0.00
Wallenpaupack														80,000	0	0.00
Total Hydro														672,000	0	0.00
Total Fuel And Cost	9,668,520	347,393,000	35.93	149,490	2,612,000	17.47	10,867,000	5,678,000	0.52	6,701,633	13,230,600	1.97	0	38,488,800	423,178,600	10.99

Pennsylvania Power & Light Company
Detailed Summary of Steam Station Projections
MWH Generation
Computation Period: January 1, 1998 - December 31, 1998

Generating Station	Total MWH
Nuclear Fueled	
Susquehanna 1	6,338,000
Susquehanna 2	7,191,000
Total Nuclear Fueled	13,529,000
Fossil Fueled	
Brunner Island 1	1,663,800
Brunner Island 2	2,076,200
Brunner Island 3	4,510,000
Brunner Is. Plant Total	8,250,000
Martins Creek 1	546,800
Martins Creek 2	653,200
Martins Creek 1 & 2 Total	1,200,000
Sunbury 1-2	1,051,300
Sunbury 3	414,200
Sunbury 4	393,500
Sunbury Plant Total	1,859,000
Holtwood 17	598,000
Keystone 1	769,600
Keystone 2	640,400
Keystone Plant Total	1,410,000
Conemaugh 1	618,600
Conemaugh 2	728,400
Conemaugh Plant Total	1,347,000
Montour 1	4,667,900
Montour 2	4,344,100
Montour Plant Total	9,012,000
Martins Creek 3	316,500
Martins Creek 4	293,600
Martins Creek 3 & 4 Total	610,100
Total Fossil Fueled	24,286,100
Total Steam Station Generation	37,815,100
Hydro	
Holtwood	592,000
Wallenpaupack	80,000
Total Hydro	672,000
Total Station Generation	38,487,100

Pennsylvania Power & Light Company
Detailed Summary of Steam Station Projections
Fuel Costs - Dollars
Computation Period: January 1, 1998 - December 31, 1998

Generating Station	Total – Dollars
Nuclear Fueled	
Susquehanna 1	26,119,000
Susquehanna 1(Spent Fuel)	6,969,600
Susquehanna 2	28,146,000
Susquehanna 2(Spent Fuel)	7,444,800
D&D Expense	2,613,600
Total Nuclear Cost (Incl. D&D Expense)	71,293,000
Coal	
Brunner Island	131,567,000
Martins Creek 1 & 2	21,208,000
Sunbury	24,725,000
Holtwood 17	6,647,000
Keystone	18,666,000
Conemaugh (Excl. Scrubber)	14,994,000
Montour	129,586,000
Total Coal Cost	347,393,000
6 Oil	
Martins Creek 3 & 4 (Excl. Sun Oil Adj.)	2,612,000
2 Oil	
Brunner Island	1,368,200
Martins Creek 1 & 2	916,600
Sunbury	233,900
Holtwood 17	27,100
Keystone	154,500
Conemaugh	55,600
Montour	1,588,300
Martins Creek 3 & 4	1,238,800
Total 2 Oil Cost	5,583,000
Natural Gas	
Conemaugh	195,600
Martins Creek #3&#4	13,035,000
Total Natural Gas	13,230,600
Total Steam Station Cost	368,818,600

Pennsylvania Power & Light Company
Detailed Summary of Steam Station Projections
Mills Per KWH
Computation Period: January 1, 1998 - December 31, 1998

Generating Station	Average Mills Per KWH
Nuclear Fueled (Excl. D&D and Spent Fuel Expenses)	
Susquehanna 1	4.12
Susquehanna 2	3.91
Total Nuclear Fueled	4.01
Fossil Fueled	
Brunner Island	16.11
Martins Creek 1 & 2	18.44
Sunbury	13.43
Holtwood 17	11.16
Keystone	13.35
Conemaugh (Excl. Scrubber)	11.32
Montour	14.56
Martins Creek 3 & 4 (Excl. Sun Oil Adj.)	27.68
Total Fossil Fueled	15.19
Average Steam Station	9.75

Pennsylvania Power & Light Company
Detailed Summary of Steam Station Projections
Units Of Fuel Consumed
Computation Period: January 1, 1998 - December 31, 1998

Generating Station	Total
Coal (Tons)	
Brunner Island	3,279,330
Martins Creek 1 & 2	531,306
Sunbury	1,058,340
Holtwood 17	394,593
Keystone	536,790
Conemaugh	508,266
Montour	3,359,896
Total Coal	9,668,520
6 Oil (Barrels)	
Martins Creek 3 & 4	149,490
2 Oil (Gallons)	
Brunner Island	2,642,000
Martins Creek 1 & 2	1,778,000
Sunbury	454,000
Holtwood 17	52,000
Keystone	300,000
Conemaugh	108,000
Montour	3,055,000
Martins Creek 3 & 4	2,305,000
Total 2 Oil	10,694,000
Natural Gas (Mcf)	
Martins Creek 3 & 4	6,644,833
Conemaugh	56,800
Total Gas	6,701,633

Pennsylvania Power & Light Company
Detailed Summary of Steam Station Projections
Cost Per Unit Of Fuel Consumed
Computation Period: January 1, 1998 - December 31, 1998

Generating Station	Average
Coal ($/Ton)	
Brunner Island	40.12
Martins Creek 1 & 2	39.93
Sunbury	23.37
Holtwood 17	16.84
Keystone	34.76
Conemaugh	29.50
Montour	38.57
Total Coal Average ($/Ton)	35.93
6 Oil ($/Barrel)	
Martins Creek 3 & 4 ($/Bbl)	17.49
2 Oil ($/Gallon)	
Brunner Island	0.52
Martins Creek 1 & 2	0.52
Sunbury	0.52
Holtwood 17	0.52
Keystone	0.52
Conemaugh	0.51
Montour	0.52
Martins Creek 3 & 4	0.54
Total 2 Oil Average ($/Gal)	0.52
Natural Gas ($/Mcf)	
Martins Creek 3 & 4	1.96
Conemaugh	3.44
Total Gas $/Mcf	1.97

EXHIBIT JMK 7

PURCHASED GENERATION COST RATE

A purchased generation cost rate (PGCR) shall be applied to each kilowatt-hour supplied to customers (without hourly metering capability) taking Basic Utility Supply Service (BUSS) from the Company under this tariff. The PGCR, determined to the nearest one-thousandth of 1 mill per kilowatt-hour in accordance with the formula set forth below, shall be applied to all kilowatt-hours billed for generation service during the billing month:

$$PGCR = \frac{PGc}{St} - \frac{E}{Sr} \times \frac{1}{(1-T)}$$

Where:

PGCR = Purchased generation cost rate stated in mills per kilowatt-hour to be applied to each kilowatt-hour supplied to customers taking generation service from the Company under this tariff.

PG_C = The estimated cost of generation purchased by the Company from any generation supply source is defined as follows:

PURCHASED GENERATION COST RATE

Generation purchases - amounts associated with generation purchases, including all applicable energy-related and capacity and/or demand-related costs, plus any electricity (generation supply) procurement costs incurred by the Company.

The computation year (c) shall be April 1 through March 31 for which the PGCR, as computed, will apply. Projections of the Company's purchased generation costs for the computation year shall include the estimated cost of generation (all applicable energy-related and capacity and/or demand-related costs) to be purchased by the Company from any generation supply source plus any electricity procurement costs incurred by the Company.

E = Experienced net over or undercollection of purchased generation costs as of the end of the 12-month period ending with the January billing period including interest. Interest shall be computed monthly at the appropriate rate as provided in Section 1308(d) of the Public Utility Code from the month the over or undercollection occurs to the effective

PURCHASED GENERATION COST RATE

month such overcollection is refunded and such undercollection is recouped.

S_t = The Company's total KWH sales to customers taking generation service under this tariff, projected for the computation year (c).

S_r = The Company's retail KWH sales to which the PGCR applies, projected for the computation year (c).

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

The PGCR so computed shall be filed with the Pennsylvania Public Utility Commission (Commission) by March 1 of each year. Such rate shall become effective for generation service rendered on an after the following April 1 unless otherwise ordered by the Commission, and shall remain in effect for a period of one year unless revised on an interim basis subject to the approval of the Commission. Upon determination that a PGCR, if left unchanged, would result in a material over or undercollection of purchased generation costs incurred or expected to be incurred

PURCHASED GENERATION COST RATE

during the current 12-month period ending January 31, the Company may file with the Commission for an interim revision of the PGCR, to become effective 30 days from the date of filing, unless otherwise ordered by the Commission.

Minimum bills shall not be reduced by reason of this PGCR, nor shall charges hereunder be a part of the monthly rate schedule minimum. The PGCR shall not be subject to any credits or discounts and shall not be affected by the state tax adjustment surcharge.

If, during application of the rate cap established by Section 2804(4) of the Electricity Generation Customer Choice and Competition Act, the PGCR causes the total rates of a rate schedule to exceed the applicable rate cap, a credit shall be applied to that rate schedule to bring that rate schedule into compliance with the rate cap.

The Company shall file quarterly reports within thirty (30) days following the conclusion of each computation-year quarter. These reports will be in such form as the Commission shall prescribe. The third-quarter report shall be accompanied by

PURCHASED GENERATION COST RATE

a tentative estimate of the purchased generation cost rate for the next computation year.

The application of the PGCR shall be subject to continuous review and to audit by the Commission at such intervals as it shall determine. The Commission continuously shall review the reasonableness and lawfulness of the level of charges produced by the PGCR and the costs included therein.

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

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00973954

PENNSYLVANIA POWER & LIGHT COMPANY

Statement No. 6-R

Rebuttal Testimony of Paul R. Moul

Q. Mr. Moul, have you previously submitted testimony in this proceeding?

A. Yes. My direct testimony was submitted on April 1, 1997 as PP&L Statement No. 6.

Q. What is the purpose of your rebuttal testimony?

A. Pennsylvania Power & Light Company (PP&L or the Company) has requested that I respond to the cost of capital testimony presented by Mr. Kevan L. Deardorff, a witness appearing on behalf of the Office of Trial Staff (OTS). I will also submit supplemental data covering capital costs during the first five months of 1997. That material is contained in Exhibit PRM 4. I will also respond to a portion of the testimony by Mr. Michael J. Gruber, another OTS witness, and to a portion of the testimony by Mr. Peter A. Bradford, a witness appearing on behalf of the Environmentalists. With respect to my rebuttal to Mr. Bradford, I have submitted two additional schedules identified as Exhibit PRM 5 and Exhibit PRM 6.

Q. Will you identify the areas of controversy concerning the rate of return in this proceeding?

A. The central areas of dispute in this case involve: (i) whether the cost of equity recommendation by Mr. Deardorff reflects the risk of PP&L and whether it will be acceptable to the financial community, (ii) whether PP&L's cost of equity has declined since the Commission's Order in the Company's last base rate case at Docket No. R-00943271, (iii) the choice of companies to be included in the Barometer Group, (iv) technical matters concerning the DCF method for measuring the cost of equity, and (v) whether other methods provide a reasonable measure of the Company's cost of equity.

The results of alternative methodologies are necessary to confirm the reasonableness of any cost of equity recommendation. Moreover, the use of more than one method will provide a range of results which will add reliability to the analysis and provide complimentary evidence of the cost of equity. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors which motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing, etc.). After all, no matter which model or inputs are used to develop the cost of equity, the final result must provide the Company with an opportunity to experience the types of returns that are necessary to attract investors. It is my opinion that the cost of equity recommendation of Mr. Deardorff fails to meet this test because it is too low by reference to alternate investment opportunities.

Q. Does the supplemental 1997 market data contained in Exhibit PRM 4 show any reduction in the Company's cost of equity?

A. No. Based upon market data available through May 1997, my cost of equity recommendation for PP&L remains at 12.75%. In my original recommendation, as set forth in my direct testimony, I employed market data that concluded with the end of the historic base period in this proceeding, i.e., December 31, 1996. In my rebuttal, I have provided further market evidence by considering an additional five months of data, i.e., from January to May 1997. Data through May 1997 was selected because it corresponds with the market data provided by Mr. Deardorff in OTS Exhibit No. 3. In considering later market data, I relied primarily on interest rates and dividend yields for PP&L and my Barometer Group.

As shown on Schedule 1 of Exhibit PRM 4, later interest rates show that the yields on A rated public utility bonds have continued to be within the range that existed for much of 1996. That is to say, for January-May 1997, the yield on A rated public utility bonds has continued to be within the range of 7.50% to 8.00%. By considering these later interest rate data, the current market evidence continues to support my original 12.75% cost of equity for PP&L.

Q. What did the later dividend yield data show?

A. As indicated on pages 1 and 2 of Schedule 2 of Exhibit PRM 4, the dividend yields have generally trended upward since the beginning of 1997. For PP&L Resources' common stock, the increase in the dividend yield has been more pronounced than my Barometer Group, thereby suggesting an even steeper increase in the Company's cost of equity as compared to other electric utilities. Although the recent dividend yields are all now higher, I continue to recommend the 12.75% cost of equity that was contained in my direct testimony.

Q. What has caused of the rise in dividend yields for PP&L and other electric companies at a time when interest rates have been relatively steady during the first five months of 1997?

A. The rise in dividend yields can be traced to a decline in the stock prices for PP&L and electric utility stocks, generally. The stock price declines for the electric utilities have occurred at a time of a continued "bull" market for the general market which have provided stellar returns this far in 1997. This is shown by the performance of the S&P 500 Composite Index, the S&P Electric Utility Index, and PP&L Resources, as shown below.

	Jan	Feb	Mar	Apr	May	YTD
S&P 500 Composite	+6.1%	+0.6%	-4.3%	+5.8%	+5.9%	+14.5%
S&P Electric Companies	+0.2%	-0.4%	-4.7%	-3.0%	+3.5%	-4.5%
PP&L Resources	-1.6%	+1.1%	-11.5%	-3.1%	+1.9%	-13.0%

While the general market as measured by the S&P 500 Composite has performed well in 1997, the electric utilities have under performed the overall market. This means that the cost of equity for the electric utility industry has increased in 1997 attributed generally to the uncertainty surrounding the restructuring of the industry.

Q. You indicated previously that one of the disputes in the case related to whether the cost of equity determined in this case would be acceptable to the financial community. How can this measured?

A. There are two means by which the cost of equity, and hence the overall cost of capital, can be measured to determine whether it will be acceptable to the financial community. The first would involve a test of the equity return to determine whether it would support the Company's stock price, and hence its financial integrity from an equity investors point of view. The second would involve the overall cost of capital to determine whether it would support the Company's credit quality, and hence its ability to raise capital from a bond investors point of view.

Q. As to the first test, can you provide an objective assessment of the recommended cost of equity suggested by Mr. Deardorff?

A. If adopted by the Commission, the rate of return on common equity recommended by Mr. Deardorff would seriously jeopardize the

Company's standing in the equity markets. In particular, the rate of return on common equity advocated by Mr. Deardorff would not support PP&L's financial integrity. As a demonstration of the inadequacy of his recommendation, the Company's earnings per share can be calculated from his recommendation and those earnings can be tested to determine whether they would adequately sustain the Company's dividend and growth potential, and hence its stock price. This analysis begins with the book value per share of PP&L Resources' common stock which was $16.88 at December 31, 1996. With this book value, I have calculated that PP&L's earnings per share would be just $1.77 ($16.87 x .105) with Mr. Deardorff's recommended rate of return on common equity. This earnings level is lower than any of the Company's earnings per share since 1988, with the exception of 1994 when a collection of unusual occurrences artificially depressed earnings. Were it not for those unusual events, the Company's 1994 earnings per share would have been well above $1.77 per share. In contrast, Value Line is forecasting earnings per share for PP&L in the $2.00 to $2.10 range for the years 1997 to 2002 -- well above that suggested by Mr. Deardorff's recommendation. Further, with the level of earnings per share reflected in Mr. Deardorff 's recommendation, the Company would have only $0.10 ($1.77 - $1.67) per share of earnings cushion above the Company's current dividend. Using the

Value Line forecasts of earnings per share noted above, the earnings cushion should be $0.33 to $0.43 per share above PP&L's current dividend. This indicates woefully inadequate earnings for the Company as suggested by Mr. Deardorff's cost of equity recommendation.

Moreover, the rate of return on common equity recommended by Mr. Deardorff does not come close to providing the growth rate he claims to use for PP&L, i.e., 2.75%. Rather, Mr. Deardorff's rate of return on common equity would provide retention growth of just 0.6% ($0.10 ÷ $16.87) for PP&L. Indeed, the actual growth implied by Mr. Deardorff's recommendation would be over two percentage points below that which he indicates would be expected by investors.

Q. What rate of return on common equity is necessary to adequately reflect analysts' expectation of growth for PP&L?

A. Mr. Deardorff has indicated that he supports a growth rate of 2.75% for PP&L. The growth component of the Company's earnings would therefore need to be $0.46 ($16.87 x .0275) per share. When added to the Company's current dividend per share of $1.67, the required earnings necessary to support Mr. Deardorff's perception of growth for PP&L would be $2.13 ($0.46 + $1.67). This would necessitate a rate of return on book common equity of 12.63% ($2.13 ÷ $16.87) which is near the 12.75% cost of equity which I determined independently for the Company. This demonstration clearly shows that Mr. Deardorff's recommendation is understated by at least two percentage points.

Q. You also indicated that credit quality was a test of the Company's capital attraction ability. How do the rates of return used in this case compare when viewed in the context of pre-tax interest coverage?

A. It is important to recognize that the financial performance measures of credit quality expected by the rating agencies represent results anticipated to be achieved, while the positions of the parties in this case represent merely opportunity rates for the Company. The comparison of pre-tax interest coverages are:

Moul's 12.75% ROE	3.91 times
PP&L's 11.5% ROE	3.65 times
Deardorff's 10.5% ROE	3.44 times

For the Company, 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. In contrast, Mr. Deardorff's recommended cost of capital will provide only 3.44 times pre-tax interest coverage. The Company's proposed 9.46% overall rate of return provides an opportunity to experience 3.65 times pre-tax interest coverage and, therefore, represents the minimum necessary to provide reasonable credit quality in this case. Moreover, the Commission's order in the

Company's last rate case provided PP&L with the opportunity to experience 3.69 times pre-tax interest coverage. Certainly, PP&L should not be denied a similar opportunity given the increasing risk of the electric utility business which has developed since the last case.

Q. The second item of dispute that you listed earlier involved PP&L's cost of equity in relation to the Commission's determination in the Company's last base rate case. Does Mr. Deardorff's testimony in this case indicate that the Company's cost of equity has declined from the time of the Company's last base rate case?

A. No. Mr. Deardorff's testimony in this case shows that the Company's cost of equity has not changed materially since the Company's last base rate case. This is shown by a comparison of his recommended cost of equity contained in each case. In this case, Mr. Deardorff recommends a 10.5% cost of equity which is approximately the same as his 10.63% recommendation in the Company's last base rate case. By reference to his testimony in each case, it is apparent that Mr. Deardorff sees little change in the cost of equity for PP&L. Indeed, for certain of his calculations, Mr Deardorff has shown no movement in the cost of equity from the Company's last base rate case to this case. Indeed, using the same DCF calculation based upon the 52 week average stock price covering the periods ending February 1995 and

May 1997, Mr. Deardorff arrived at the exact same result for PP&L. Using spot prices, Mr. Deardorff shows a higher cost of equity in May 1997 as compared to February 1995. In the Company's last base rate case, the Commission set the Company's rate of return on common equity at 11.5%, or approximately one percentage point higher than Mr. Deardorff's recommendation. The Commission should do likewise in this case for PP&L. Hence, the Commission would be fully justified in using the same cost of equity for calculating the Company's stranded or transition costs in this proceeding that it determined in the Company's last base rate case.

Q. Do you have additional support that indicates that the Company's cost of equity has not declined since the Commission's determination in the last base rate case?

A. Yes. The growth rate forecasts for PP&L and the Barometer Group are now higher than they were in 1995, which confirms my assessment that the cost of equity is not lower than it was in the Company's last base rate case. The following table shows a comparison of the forecast earnings per share growth rates in 1997 as compared with the growth rates presented by Mr. Deardorff in the Company's last base rate case in 1995.

	First Quarter 1995	Second Quarter 1997	Change
PP&L			
Value Line	1.0%	2.5%	+1.5%
S&P	2.0%	3.0%	+1.0%
Barometer Group			
Value Line	3.4%	3.8%	+0.4%
S&P	2.63%	3.3%	+0.67%

From the data shown above, it is apparent that the forecast growth rates of earnings per share show that there is no offsetting decline in the growth component of the DCF model which would counter-balance the rise in the dividend yield in 1997 which Mr. Deardorff described in his testimony. Indeed, there is no justification that would warrant a reduction in PP&L's cost of equity which was set by the Commission at 11.5% in the Company's last base rate case.

Q. The third item of dispute which you listed concerned the selection of companies for Barometer Group purposes. Do you agree with Mr. Deardorff's selection of the companies he used to assemble his Barometer Group?

A. No. Mr. Deardorff should have employed the same companies which he used in the Company's prior base rate case when assembling his Barometer Group. In this case, he has deleted five companies (Allegheny Power, American Electric Power, Delmarva, DPL, and Potomac Electric Power) which he used in the Company's prior base rate case and substituted ten new companies. Mr. Deardorff's deletion of companies that he used in the Company's last rate case should not be condoned because: American Electric Power and Delmarva have nuclear generating assets, Allegheny Power has operations in Pennsylvania and is in the process of merging with DQE, and Potomac Electric Power is a member of the PJM and is in the process of merging with Baltimore Gas & Electric. Mr. Deardorff erroneously included the following companies in his Barometer Group which have previously cut their dividends: Boston Edison, DQE, GPU, PECO, Rochester G&E, and Unicom. These companies are not comparable to PP&L, which has not reduced or eliminated its dividend. Moreover, Mr. Deardorff erroneously included the following companies which are too remote geographically from PP&L to be included in his group: Boston Edison that does business in Massachusetts, Carolina Power & Light that does business in North and South Carolina, Dominion Resources that does business in Virginia and North Carolina, Duke Power that does business in North and South Carolina, IES Industries that does business in Iowa, and Unicom that does business in Illinois. Rather, Mr. Deardorff should have continued to use the group of comparable companies that represented his Barometer Group in the Company's prior base rate case. Had he done so, he would not have challenged the Barometer Group that I used in this case.

Q. Do you agree with Mr. Deardorff's assertion that the percentage of nuclear generating capacity is an important criteria for assembling companies for Barometer Group purposes in this case?

A. An investment in nuclear generating capacity does indicate that an electric utility can be faced with the need for stranded cost recovery, but it should not be a determining factor for assembling companies for the Barometer Group in this case. Indeed, stranded costs arise from not only investments in high fixed cost nuclear generating assets, but also from fossil fuel generating assets, high cost purchased power contracts, and regulatory assets.

Q. Please explain your fourth point concerning disagreements with Mr. Deardorff concerning the DCF measure of the cost of equity?

A. In my opinion, DCF should not be the sole measure of the Company's cost of equity. No single approach is sufficiently reliable to adequately establish the cost of equity without further verification. This is particularly true today given the wide swings in share values. As such, the cost of equity should not be measured by reference to a single method. The use of a single method by Mr. Deardorff significantly reduces the value of his testimony in this case. This is because his testimony contains no point of reference which would allow an assessment of his DCF results. Using the same DCF method with

Barometer Group data provides no independent confirmation of his results for PP&L because the same infirmities of the DCF arise using proxy companies as well.

Q. What form of the DCF model has been employed in this case?

A. The constant growth or "Gordon" form of the DCF model has been used by Mr. Deardorff and me. It must be recognized, however, that the "Gordon" form of the DCF model is not without its limitations because many of the assumptions which must be made to utilize this model are simply not realistic. According to the theory of the constant growth form of the DCF, future earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same constant rate absent any change in dividend payout and price-earnings multiple. However, there is no evidence that these conditions actually prevail in the equity markets. Indeed, Mr. Deardorff's evidence shows that these steady-state (i.e., constant growth) conditions represent unrealistic assumptions of investor expectations. For example, OTS Exhibit No. 3, Schedule 5, page 4 indicates that dividend payout ratios are forecasted to decline in the future. This means that earnings per share, and hence price appreciation (i.e., the capital gains yield, or growth component of the DCF) will be at a higher rate than dividend growth in the future.

I should further explain that there is an element of circularity in the DCF model when applied in public utility ratesetting. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations which include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility because the model may not deal with the high risk traits of a utility with low growth.

Q. Mr. Deardorff specifically challenges your ex-dividend adjustment in the calculation of the dividend yield component of the DCF. Please respond.

A. Preliminarily, I should note that Mr. Deardorff proposes that the dividend yield component should be adjusted in a forward-looking manner with the formula D_0/P_0 (1 + .5g). The Commission has routinely followed this procedure in rate case decisions (including the Company's last base rate case) when utilizing the periodic (i.e., discrete) form of the DCF model. I have also followed this procedure. It appears, however, that Mr. Deardorff has not applied the Commission approved adjustment to the dividend yield. Instead, he has used a forecast of dividend payments by Value Line which has the affect of reducing Mr. Deardorff's dividend yields. If he had followed the accepted approach in the adjustment to the dividend yield, his DCF calculations would have increased by 0.11% using PP&L market data and also 0.11% using the Barometer Group market data. In addition, I computed yields based on discrete quarterly dividend growth and quarterly compounding. These are entirely reasonable refinements to developing adjusted dividend yields.

As for my adjustment to recognize the ex-dividend date, while Mr. Deardorff may believe that this adjustment is unnecessary, the availability of data through electronic sources and the increased use of personal computers have allowed this refinement to increase the accuracy of the dividend yield computation. The Wall Street Journal and Barron's regularly report when a stock trades ex-dividend. The ex-dividend date is reported to investors in each edition of the Value Line Investment Survey that Mr. Deardorff has used as one of his sources in this case. In addition, the Standard & Poor's monthly Stock Guide also provides ex-dividend dates for all common stocks. The wide availability of ex-dividend dates and the market's pricing of a stock trading ex-dividend are not obscure occurrences which should be ignored in a comprehensive analysis of the cost of equity.

Q. Mr. Deardorff quarrels with your recognition of qualitative factors in the development of the DCF growth component. Is it necessary to consider these factors when formulating a DCF growth rate for an electric utility, such as PP&L?

A. Yes. Preliminary, I must indicate that Mr. Deardorff's apparent desire for the quantification of qualitative factors defies the rational underlying these market-wide factors. In this regard, forecasts of earnings per share do not fully encompass market-wide factors because investors make independent assessments concerning these factors (i.e., their pricing decisions reflect general market sentiment). For that matter, it is not generally known to what extent securities analysts incorporate market-wide factors into their estimates, or whether analysts do this uniformly. Further, fundamental analysis which is employed in reaching a growth rate forecast is a company-specific determination which cannot fully account for all market-wide factors. It should also be remembered that analysts' forecasts -- which take a short-term view of the future using accounting values -- are poor predictors of price appreciation. Valuations in the market are influenced by relative P/Es, dividend yields, interest rates, the supply of stocks, etc. In addition, it is reasonable to assume that recent forecasts by analysts for the electric utilities are overly conservative because no one can be sure of the winners/losers in the new competitive environment. While it is true that such market factors could possibly result in negative growth, as suggested by Mr. Deardorff, these factors today only add to investor expectation of higher stock prices in an exuberant "bull" market.

Q. Please respond to the testimony of Mr. Deardorff concerning your Risk Premium approach.

A. Mr. Deardorff makes the unfounded assertion that while the Risk Premium approach, and also CAPM, is relevant to investment decision making, that relevancy does not carry over to the ratesetting process. He also asserts that by comparing the results of the Risk Premium, and also CAPM, with expected returns from the DCF, that investors can make rational buy and sell decisions. For these very reasons, other methods should be used in addition to DCF in the development of the cost of equity in this proceeding. As noted earlier, it is necessary to have a frame of reference provided by other models to confirm the reasonableness of the DCF results.

As to Mr. Deardorff's assertion that the Risk Premium does not measure the current cost of equity as directly as DCF, such a claim is without foundation. First, the Risk Premium approach uses current and forecast interest rate data, which represents the major component of the cost of equity expressed in terms of this model. Second, I have not claimed that there is a "constant" risk premium. The risk premium does react to changes in economic and market fundamentals. For that reason, I have utilized the more recent data from my risk premium study in order to more nearly match the business and economic fundamentals expected for the future with data taken from the past. Finally, with the increasing risk of the electric utility business, the risk premium for the future can only be expected to expand from that which existed in the past.

Q. Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, Risk Premium results should be given serious consideration, particularly under current market conditions. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides a foundation for the cost of equity which must be higher in recognition of the risk of equity which exceeds investors' risk of lending capital to a firm. As such, the Risk Premium results are more responsive to changes in the cost of capital than some other methods.

Q. Mr. Deardorff has also objected to your use of the CAPM. Will you comment?

A. Yes. My comments stated above regarding Mr. Deardorff's criticisms of the Risk Premium approach also apply to the CAPM. In my application of the CAPM model, I have used current and forecast interest rates in order to measure the current cost of equity, and I have used historical and forecast market returns to reflect current economic conditions.

Q. Mr. Deardorff also claims that a recent study by Fama/French has discredited the beta measure of risk in the CAPM. Please comment.

A. The Fama/French study found that book to price ratios ("B/P") and the size of a firm were additional factors necessary to explain returns on stocks. The implications of the Fama/French study is that B/P and size must be considered separately from the measure of market risk (i.e., the beta). That is to say, the Fama/French model of the expected returns on a portfolio in excess of the risk-free rate of return includes three factors, one of which is beta.

In addition, if the value of betas is to be questioned, then the entire efficient market hypothesis is also questionable. The bottom line is that if the beta component of CAPM is deficient, then so is the efficient market hypothesis (especially in its strong form) which also makes the DCF defective because it is also founded on the efficient market hypothesis. Further, subsequent studies have indicated that beta remains useful -- "Reports of Beta's Death Have Been Greatly Exaggerated," The Journal of Portfolio Management, Spring 1996, by

Kevin Grady and Burton G. Malkiel and "The Conditional CAPM and the Cross-Section of Expected Returns," The Journal of Finance, March 1996, by Ravi Jagannathan and Zhenyu Wang.

Q. Please respond to Mr. Deardorff's assertion that the Risk Premium and CAPM methods rely upon some form of the DCF.

A. Mr. Deardorff never explains how a DCF calculation plays a role in the Risk Premium and CAPM models. If he means that holding period returns form the basis of the asset series (i.e., stocks, bonds, etc.) used to compute the differential which represents the risk premium or market premium, then these holding period returns are vastly different from the type of DCF analysis undertaken by Mr. Deardorff in his direct testimony. The use of holding period returns to measure the variables in the Risk Premium and CAPM in no way provides an endorsement of the superiority of the DCF model as applied in this case.

Q. Has Mr. Deardorff adequately addressed the relative risk of PP&L?

A. No. As indicated by Mr. Deardorff, the volatility of PP&L's stock price has increased in comparison to his Barometer Group. My earlier analysis confirms this fact. When the volatility of a stock increases, it is a sign that its risk also increases and thereby increases its cost of equity. Unfortunately, by incorporating the results of his Barometer

Group in his recommendation, Mr. Deardorff has failed to fully recognize the Company's higher risk when recommending a cost of equity in this case. The higher risk of PP&L is not new, because all of the market evidence presented in the Company's last base rate case also showed that PP&L had a higher cost of equity vis-a-vis the Barometer Group. This was evident well before this case was filed by PP&L.

Q. Mr. Deardorff also provides testimony concerning a risk-free rate of return. Please comment.

A. At the request of OTS witness Gruber, Mr. Deardorff indicates that 6.6% represents a risk-free rate of return based upon a forecast of the yield on a ten year Treasury notes. This is not an appropriate rate for PP&L because the Company cannot obtain permanent long-term capital equivalent to the yield on an obligation of the U.S. Treasury. Rather, the closest interest bearing obligation that could be taken for a risk-free rate of return would be the yield on AAA rated public utility bonds. The interest rate on AAA rated public utility bonds is the lowest possible rate at which PP&L, or any electric utility could obtain permanent long-term capital from investors. Although PP&L's credit quality is well below the AAA rating (i.e., the Company's bond rating is A-), it is conceivable that the Company could obtain funds at the AAA equivalent rating through a credit enhancement or through the securitization of its stranded cost based upon a qualified rate order issued by the Commission. Examples of interest rates on Aaa rated public utility bonds, as measured by the Moody's index, are:

Years	Aaa bond yield
1992	8.19%
1993	7.29%
1994	8.06%
1995	7.68%
1996	7.48%
Six months to June 1997	7.64%

This clearly shows that a 6.6% risk-free rate of return should not be used in the development of the Company's competitive transition change.

Q. Do you agree with the testimony of OTS witness Gruber which asserts that due to the low alleged risk associated with the collection of the Competitive Transition Charge (CTC) that the Company should not receive its full return on the equity component of its capital structure?

A. No. Mr. Gruber has not made a convincing argument that would support his position that the Company be denied its full return on equity associated with the collection of the CTC. There are both practical and theoretical reasons that indicate that the Company is faced with significant risk during the collection of the CTC.

Q. Why is it the collection of the CTC during the period 1999 through 2005 not a risk-free undertaking?

A. The riskiness surrounding the collection of the CTC involves: (i) the rate cap that will limit the overall charges by the Company to its customers during the collection period, (ii) the large number of assumptions that were used in calculating the transition or stranded costs that serve as the basis for the CTC, (iii) the lack of a true-up of actual costs with estimated costs used to calculate the transition or stranded costs, (iv) the Company's use of a cost of capital calculated at December 31, 1996 which may turn out to be unreflective of the actual capital costs which may prevail during the period 1999 to 2005, and (v) the use by the Company of a lower rate of return on common equity than I have determined independently to be required by investors.

Q. How does the rate cap affect the riskiness associated with the CTC?

A. The amount of CTC that can be collected from customers is limited by the rate cap which was imposed by the Electricity Generation Customer Choice and Competition Act (Act). Under the Act, rates that can be charged to PP&L's customers cannot exceed those that were in effect on January 1, 1997. It is my understanding that if future customer charges for generation turn out to be lower than expected in this case, then PP&L cannot increase its CTC in order to increase its stranded cost recovery because the level of CTC charges will be fixed in this case. Under a different scenario of higher than expected costs for generation, the Company may be faced with serving customers returning to PP&L from other energy suppliers and may need to acquire additional generating capacity at higher costs. If these cost increases cause the total charges to customers to exceed the rate cap, then PP&L will be forced to credit customers' bills thereby effectively reducing stranded cost recovery. These scenarios show that the rate cap can cause PP&L to under recover its stranded costs and hence does not make this a risk free undertaking. These risks of under recovery of stranded costs are aside from the under collection of $600 million (revised upward from $400 million) of stranded costs described in the direct testimony of Mr. Hill.

Q. Do the uncertainties surrounding the measurement of the Company's transition or stranded costs show that there are risks associated with the CTC?

A. Yes. Mr. Gruber's testimony seems to leave the impression that the Company is somehow "guaranteed" recovery of its CTC, and thus has reduced risk. This assertion is incorrect due to the large number of estimates that are necessary to forecast the variables necessary to calculate the transition, or stranded costs for PP&L. Given the fact that in some cases the estimates represent forecasts of costs extending up to 30 years into the future, there is greater uncertainty surrounding these estimates than usually encountered in developing the cost of service (i.e., revenue requirements) in traditional rate cases which normally involve forecasts for a year or two in the future. This shows the high risk surrounding the development of the transition, or stranded costs which serve as the basis for the CTC.

Q. Mr. Gruber refers to a true-up at the end of each year as a risk-reducing feature of the CTC. Please comment.

A. While there may be an annual reconciliation for variations in sales during the nine year collection period of the CTC, there will be no true-up for the actual prices obtained by PP&L in the competitive market for electricity versus the estimates of those prices used in this proceeding. Hence, there is significant risk associated with future costs which may diverge significantly from the estimates used in this case.

Q. Previously, you mentioned that the Company's December 31, 1996 capital costs may be unreflective of future capital costs. How does this impact the risk associated with the CTC?

A. I discussed this factor in my direct testimony, PP&L Statement No. 6, and will not repeat the risk implications here. It is noteworthy to reiterate that changes in the Company's capital structure and its embedded costs of debt and preferred stock could also affect the full recovery of its stranded costs through the CTC. This represents another risk factor surrounding the CTC.

Q. Finally, you indicated that the Company employed a lower rate of return on common equity than was indicated in your direct testimony. How does this affect the Company's risk associated with the collection of the CTC?

A. In calculating the CTC, it is necessary to compute the carrying charges on the unamortized balance during the seven year collection period. To the extent that the Company utilized an 11.5% rate of return on common equity which is less than my independently determined 12.75% investor-required cost of equity, it shows that the Company will not be fully compensated for its cost of capital during the collection period of CTC. This increases the Company's risk since the amounts collected under the CTC will not be fully compensatory for the Company.

Q. Do you have any final comments on Mr. Gruber's testimony?

A. Mr. Gruber has mistaken the risk implications associated with the collection of the CTC. There are a variety of events that could occur that could seriously affect the Company's ability to fully recover its transition, or stranded costs through CTC. Further, there is significant risk to the Company that the calculation of stranded costs may be mis-estimated. The risk of both under recovery and the risk of a mis-estimate of the stranded costs indicates that the collection of the CTC does not represent a risk-free undertaking by the Company. Therefore the CTC's carrying charges should be set at the Company's cost of capital to reflect the financing which the Company has previously undertaken to provide the capital for the assets represented by stranded costs. The Company's common stockholders cannot be expected to accept a 4 to 5 percentage point reduction in their required return on capital already invested in the Company's assets represented by stranded costs. The Company must receive carrying charges on the unamortized balance of its transition, or stranded costs because revenues collected in the future are worth less today unless carrying-charges are applied to the unamortized balance.

As an aside, to the extent that the Company engages in the securitization of some of its stranded costs, then the interest rate on the bonds issued to mitigate these costs should represent the carrying charges on the unamortized balance of those stranded costs. My *previous discussion concerning the yield on AAA rated public utility* bonds would be a case-in-point in this regard. This is required because the investors that purchase the asset-backed bonds must be paid interest and repaid their principal. This then would provide the basis for the Intangible Transition Charge ("ITC").

Q. Mr. Bradford, in Environmentalists' Statement No. 3, asserts that investors in utilities have previously been compensated for the risk of potential loss of their investments due to stranding or by some other means. Please comment.

A. Mr. Bradford has cited to a study prepared by Michael Foley which compiled the utility shareholder returns over the 21 year period 1972-1992. The study used three methods of computing shareholder returns. This study purports to show that with each of these measures the returns realized by investors in electric and telecommunications companies were higher than those experienced by investors in non-regulated industrial corporations. Mr. Bradford's interpretation of these data suggest to him that utility investors, like non-regulated industrial investors, have been compensated for the risk that some of their investment could be lost by stranding or other means. Mr. Bradford further attempts to buttress his argument by observing that utility stocks have traded above their book values for much of this period.

Unfortunately, these observations by Mr. Bradford do not support his argument that utility investors have somehow already been compensated for the risk associated with the possible under recovery of stranded costs.

Q. Based upon your review of the study prepared by William Foley, can any conclusions be drawn as to past compensation provided to utility investors for potential losses due to stranded investment?

A. No. The study prepared by William Foley can, in no way, support the argument that utility investors have been previously compensated for *the potential losses due to stranded investment. No conclusion, in this* regard, can be drawn from this study, which covered the years 1972-1992, because:

- Investors during that time period could not have been fully informed that the electric utility industry would undergo restructuring in the manner proposed here. Hence, investors could not have incorporated the risk implication of stranded investment during the years 1972-1992.
- The purpose of the William Foley study was not to ascertain whether investors were compensated for the risk of potential losses due to stranded investment, rather to rank electric utilities and telecommunications companies according to the

returns realized by their investors vis-a-vis the Standard & Poor's ("S&P") Industrial Index and the Value Line Industrial Composite in order to determine the adequacy of the returns and the ability to attract capital.

- The William Foley study did not address the myriad of factors which distinguish regulated utilities from non-regulated industrial companies, including the large difference in financial risk -- utilities typically employ more senior capital (i.e., debt and preferred stock) in their capital structures thus having more financial risk than non-regulated industrial firms.
- While the William Foley study purports to conclude that the various measures of returns for utility investors suggest that utilities' earnings were adequate and that utilities were able to attract capital, Mr. Bradford has made no showing that for

longer, or more recent periods, that this conclusion can be drawn from that data[1].

Q. Are business fundamentals today materially different from the business environment which existed during the period 1972-1992?

A. Yes. At the beginning of the 1972-1992 period, the US economy was operating under wage and price controls which existed from August 15, 1971 through April 30, 1974. Also during that period, the U.S. was engaged in the Vietnam conflict, had just allowed the dollar to be converted into gold, and was about to experience the first energy crisis caused by the Arab oil embargo which began on October 22, 1973. The electric utility industry at that time was continuing to aggressively add new generating capacity and Con Ed had not yet skipped its quarterly dividend which occurred in April 1974. Thereafter, a multitude of events transformed the U.S. economy generally and the electric utility industry specifically. Today, there is generally more than adequate electric generating capacity in most of the U.S., and the electric utility industry has entered an entirely new business

[1] Indeed, in a press release issued by the Public Service Commission of Wisconsin ("PSCW") commenting on the results of an earlier study showing similar results to the William Foley study, "...the PSCW report concludes that the relatively strong performance of the utility stocks was due primarily to changes in economic conditions (namely declining inflation and interest rates in the 1980s) and not to excessively high authorized rates of return."

environment which hardly resembles most of the period spanning the years 1972-1992.

Q. Does an update of the William Foley study continue to support Mr. Bradford's assertion that utility investors have been compensated historically for the risk of potential losses from stranded costs?

A. No. An update of the William Foley study shows that for the period 1972-1996 electric utilities have not performed as well as non-regulated industrial firms, thereby dispelling the myth that shareholder returns from electric utilities have been more than adequate to compensate for risks, such as potential losses from stranded costs. Indeed, the results of the update included in Exhibit PRM 5 show that the electric utilities have under performed the non-regulated industrial companies over the period 1972-1996 and severely under performed for the period 1992-1996. The transposition of the results of the William Foley study attributed to the inclusion of four additional years of data shows that the choice of years can have a dramatic impact on the study results. Further, by adding the years 1993-1996 to the William Foley study, the recent data provides a more current reading of investors' assessment of the risk of the electric utility industry including the implications of restructuring. Therefore, it cannot be said that investors have been compensated for the risk associated with the potential stranding of their investment.

Q. How do the returns experienced by PP&L shareholders compare with the overall electric utility performance included in your update?

A. Using the William Foley study as a base, and updating with data through 1996, the internal rates of returns listed below provide the returns realized by PP&L's shareholders compared with the electric utilities generally and returns realized on the S&P 400 Industrial Index:

	Internal Rate of Return 1972-1996	Internal Rate of Return 1992-1996
S&P 400 Industrials	10.80%	15.11%
Electric Utilities	9.52%	8.09%
PP&L	10.04%	4.46%

While the returns for PP&L and electric utilities generally were similar over the period 1972-1996, more recent returns realized by PP&L's stockholders over the period 1992-1996 shows that there is no reason to believe that the Company's shareholders were compensated for the potential loss from stranded costs. This conclusion is confirmed by the market performance data presented to PP&L's common stockholders as shown on page 14 of the Company's 1997 proxy statement (see Exhibit PRM 6). Those returns were: 15.22% for the S&P 500 Index, 6.99% for the EEI Index, and 4.33% for PP&L Resources. Further, as indicated earlier in my rebuttal testimony, PP&L's common stock price declined another 13% through May 1997, thereby showing a more profound negative assessment of the Company's prospects as compared to the electric utility industry generally. As such Mr. Bradford's assertions concerning prior compensation for the potential loss from stranded cost should be disregarded.

Q. Please summarize your rebuttal testimony.

A. In my opinion, the rate of return on common equity recommended Mr. Deardorff fails to adequately reflect the many factors which influence investors and, hence, the Company's cost of equity. It is important to consider alternative methods to measure the cost of equity which incorporate the complex set of variables considered by investors when formulating expectations for the Company. This is because investors evaluate, on a relative basis, the earnings of other similarly situated companies (foundation for comparable earnings approach), interest rates (the bond yield component of risk premium), and relative stock price performance (the beta measure of systematic risk in the CAPM). Since DCF does not directly address these issues, the recommendation of Mr. Deardorff significantly understates the Company's cost of equity. Based on recent developments in the financial markets, I am convinced that my initial cost of equity proposal of 12.75% continues to be appropriate for the Company. This evidence, as well as the data provided earlier in my direct testimony, indicates that the Company's cost of equity is no lower than that determined by the Commission in the Company's last base rate case.

With regard to the issue of the CTC, Mr. Gruber has significantly misperceived the risk surrounding the collection of the CTC. There is no basis to reduce the Company's cost of equity due to any change in risk associated with the CTC. Finally, recent market evidence dispels the myth that electric utility common stockholders have been compensated in the past for the risk of potential loss due to stranded investment. As such, Mr. Bradford's testimony on this issue should be disregarded.

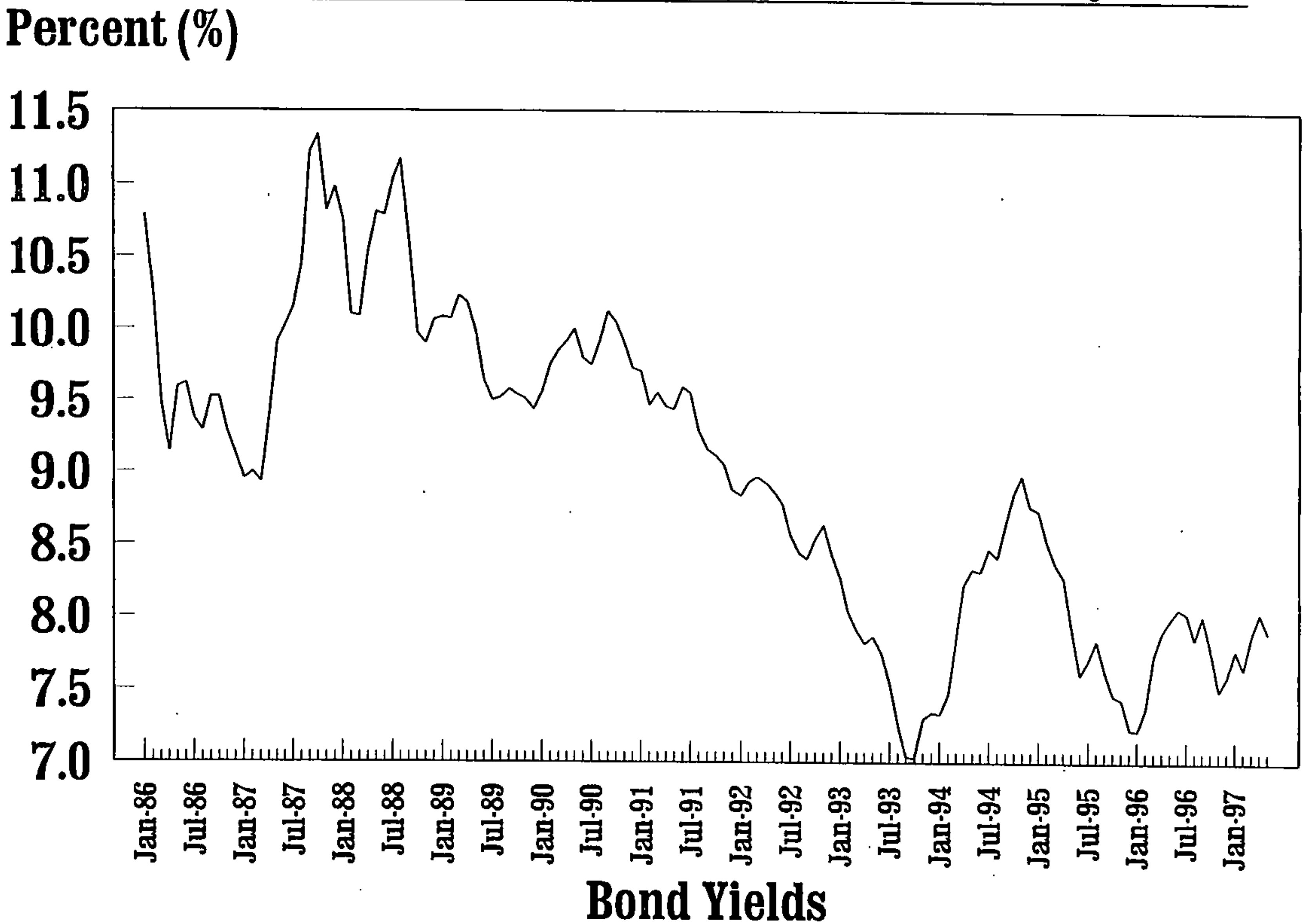
Q. Does this conclude your rebuttal testimony?

A. Yes.

EXHIBIT PRM 4

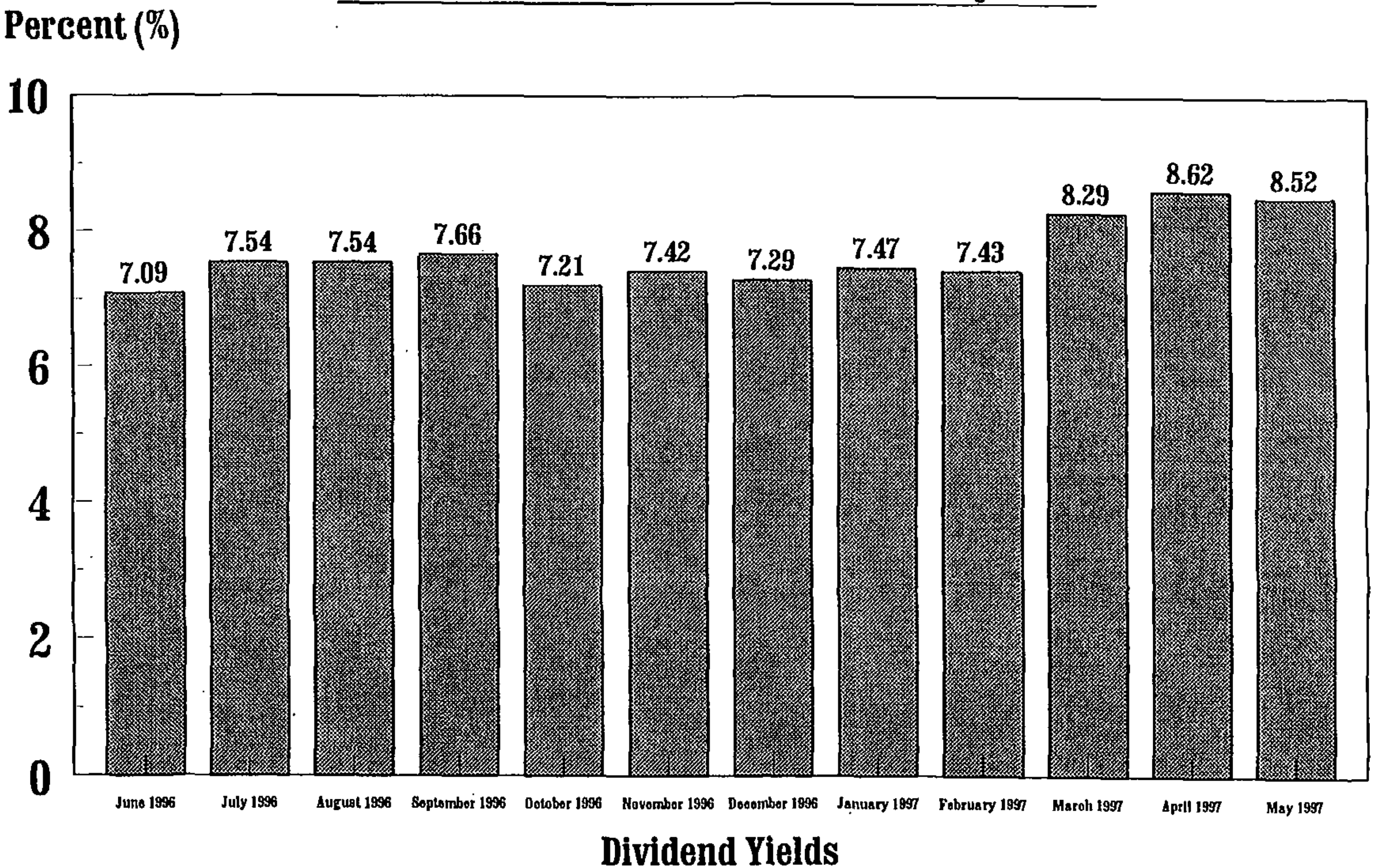
Interest Rate Trends from January 1986 to May 1997

Moody's A Rated Public Utility Average Monthly Yields

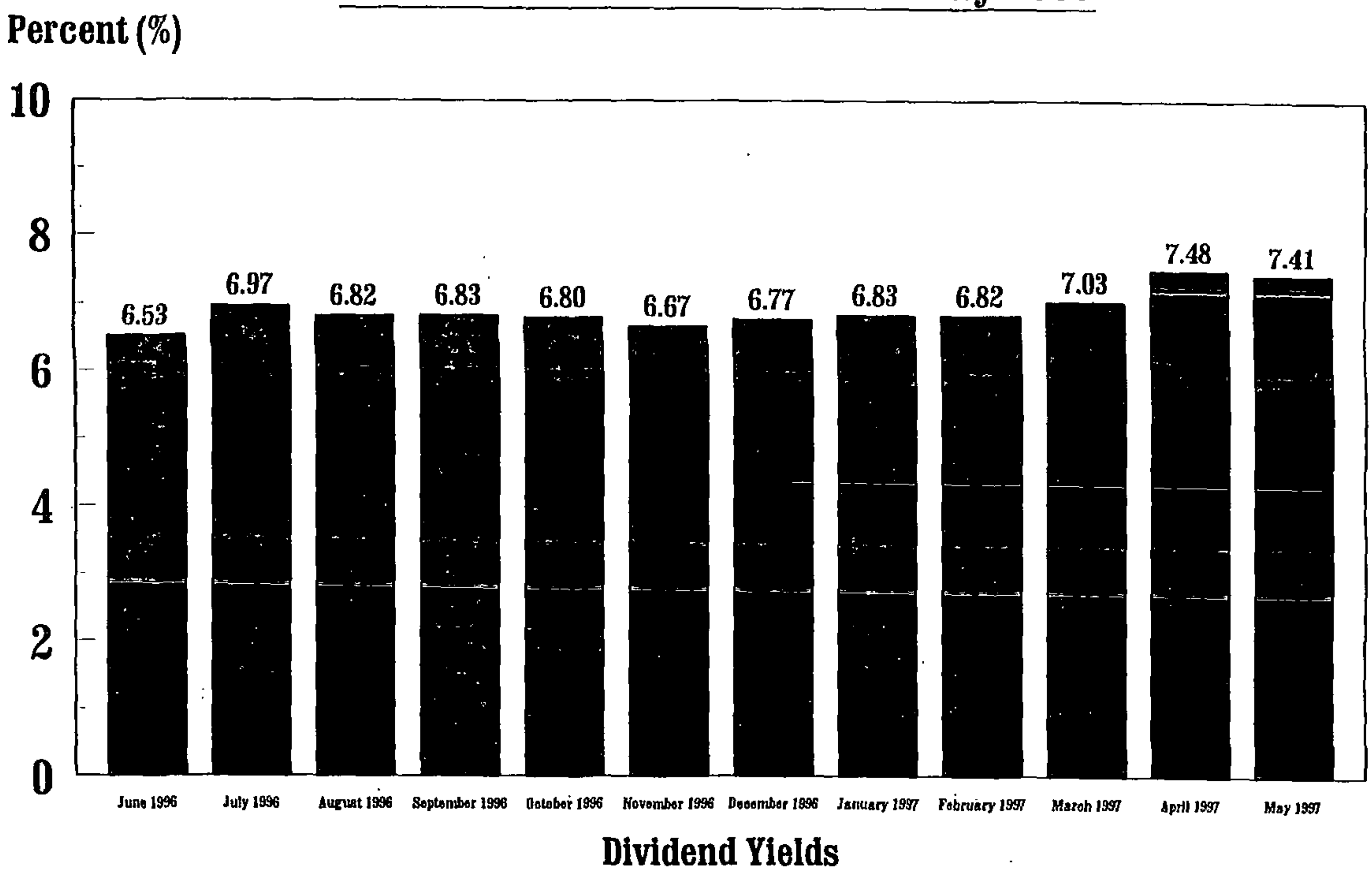


Schedule 1

PP & L Resources, Inc.
Monthly Dividend Yields
for the Twelve Months Ended May 1997



Barometer Group of Eight Electric Companies
Monthly Dividend Yields
for the Twelve Months Ended May 1997



Schedule 2
Page 2 of 2

EXHIBIT PRM 5

PP&L Resources, Inc.
NARUC Study Update
Internal Rate of Return for Electric Utilities and the S & P Induistrials
for the Years 1972-1996 and 1992-1996

Company	Internal Rate of Return for 1972-1996	Internal Rate of Return for 1992-1996
Allegheny Power System	11.07%	14.08%
American Electric Power	8.37%	13.35%
Atlantic Energy	9.93%	2.62%
Baltimore Gas & Electric	10.73%	12.11%
Bangor Hydro-Electric	7.59%	-5.01%
Boston Edison	8.42%	7.93%
Carolina Power & Light	9.69%	14.53%
Central & Southwest Corp.	9.18%	6.60%
Central Hudson Gas & Electric	9.18%	8.72%
Central Illinois Public Service	9.52%	14.32%
Central Maine Power	7.94%	-5.16%
Cilcorp Inc	8.62%	8.80%
Cincinnati Gas & Electric	9.45%	12.84%
CMS Energy	5.25%	16.65%
Commonwealth Edison	6.87%	3.79%
Commonwealth Energy System	11.56%	12.36%
Consolidated Edison	13.79%	8.20%
Delmarva Power & Light	10.05%	6.67%
Detroit Edison	8.75%	6.22%
Dominion Resources	9.07%	8.82%
DPL, Inc	9.49%	14.07%
DQE, Inc.	7.39%	3.33%
Duke Power	11.77%	14.04%
Eastern Utilities	7.99%	3.24%
El Paso Electric	4.46%	-0.02%
Empire District Electric	9.92%	1.22%
Entergy	5.80%	4.15%
Florida Progress	8.99%	9.25%
FPL Group	9.23%	12.05%
GPU, Inc	8.87%	12.41%
Hawaiian Electric Industries	10.73%	4.03%
Houston Industries	6.54%	8.52%
IES Industries	9.66%	8.40%
Illinois Power	6.02%	9.35%
Interstate Power	9.68%	6.25%
Ipalco Enterprises	9.60%	-1.53%
Kansas City Power & Light	10.57%	11.24%
Kentucky Utilities	9.97%	8.64%
Long Island Lighting	5.85%	2.57%
Louisville Gas & Electric	8.15%	14.65%
MDU Resources	11.81%	13.63%
Midwest Resources	10.50%	4.72%
Minnesota Power & Light	11.58%	3.02%
Montana Power	7.73%	2.44%
Nevada Power	10.09%	8.35%
New England Electric	11.83%	7.98%
New York State Electric & Gas	9.20%	1.25%
Niagara Mohawk Power	7.42%	-12.81%
NIPSCO	6.08%	16.80%
Northeast Utilities	8.57%	-0.48%
Northern States Power	11.88%	10.03%
Ohio Edison	7.85%	8.01%
Oklahoma Gas & Electric	8.00%	9.39%
Orange & Rockland	10.52%	5.85%
Otter Tail Power	11.99%	6.54%
Pacific Gas & Electric	9.49%	-0.23%
Pacificorp	9.63%	4.80%
PP&L Resources	10.04%	4.46%
PECO	8.37%	9.22%
Pinnacle West	8.42%	14.67%
Portland General Electric	8.78%	26.47%
Potomac Electric Power	12.11%	7.20%
Public Service of CO	8.64%	14.74%
Public Service of NM	6.91%	12.85%
Public Service Enterprise Grp	10.09%	8.11%
Puget Sound Power & Light	10.06%	5.67%
Rochester Gas & Electric	8.83%	5.59%
San Diego Gas & Electric	10.22%	6.19%
Scana	9.67%	13.14%
SCEcorp	11.77%	0.69%
Sierra Pacific Resources	8.74%	10.47%
Southern Company	9.84%	14.77%
SIGECO	13.06%	7.15%
Southwestern Public Service	11.93%	8.14%
St Joseph Light & Power	10.93%	5.67%
Teco Energy	11.11%	11.29%
Texas Utilities	6.87%	8.02%
Tuscon Electric Power	10.22%	34.38%
Union Electric	10.25%	10.07%
United Illuminating	8.57%	5.84%
Utilicorp United	14.22%	8.93%
Washington Water Power	10.04%	9.27%
Western Resources	10.00%	9.05%
Wisconsin Energy	14.11%	7.98%
Wisconsin Public Service	13.10%	8.02%
WPL Holdings	11.68%	3.91%
Average for Electric Utilities	9.52%	8.09%
S&P Industrials	10.80%	15.11%

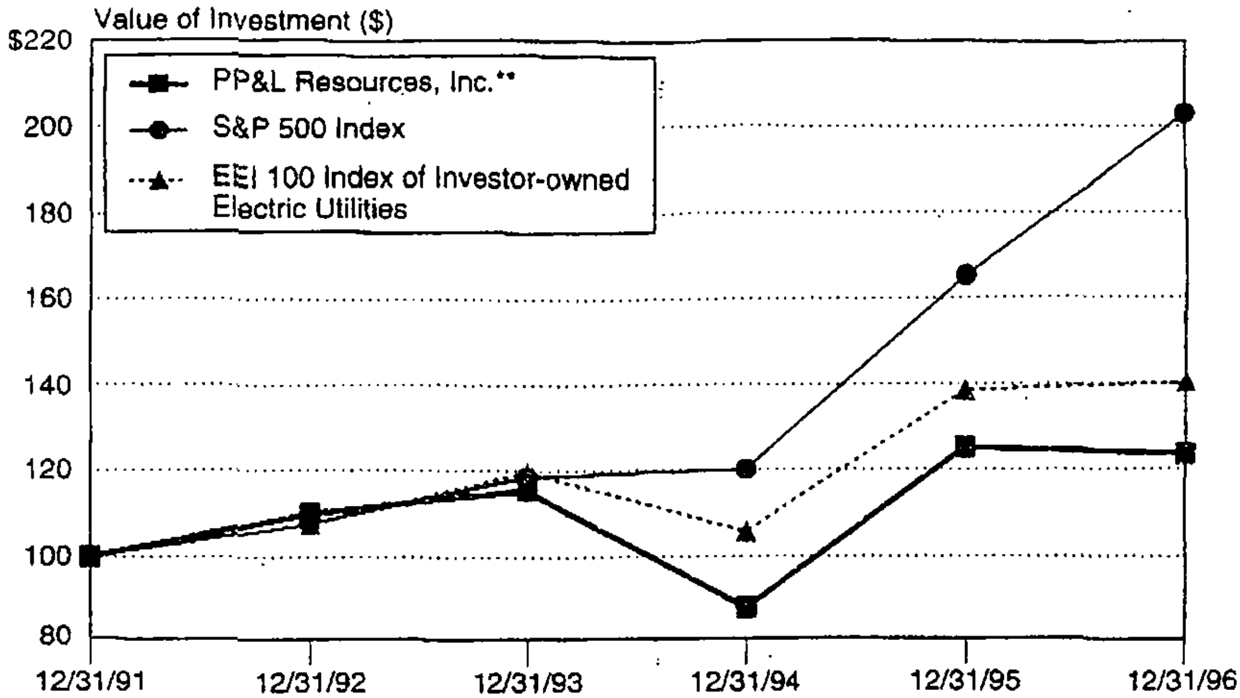
Source of Information: Electric and Telephone Utility Stockholder Returns: 1972-199
(Foley and Thompson, NARUC September 13, 1993)
OneSource, S&P Utility Compustat
S&P Statistical Service - Current Statistics
& Security Price Record

EXHIBIT PRM 6

STOCK PERFORMANCE GRAPH

The following graph depicts the performance of the Company's common stock over the past five years. For comparison purposes, two other indices are also shown. The Standard & Poor's 500 Index provides some indication of the performance of the overall stock market, and the EEI 100 Index of Investor-owned Electric Utilities reflects the performance of electric utilities' stock generally. The EEI 100 Index is a comprehensive, widely recognized industry index that includes approximately 100 investor-owned domestic electric utility companies. These companies serve 99% of the customers of the investor-owned domestic electric utility industry.

Comparison of 5-Year Cumulative Total Return
For PP&L Resources, Inc., S&P 500 Index, and
EEI 100 Index of Investor-owned Electric Utilities*



	12/31/91	12/31/92	12/31/93	12/31/94	12/31/95	12/31/96
PP&L Resources, Inc.**	100.00	110.05	115.37	88.07	125.10	123.60
S&P 500 Index	100.00	107.62	118.46	120.03	165.13	203.05
EEI 100 Index of Investor-owned Electric Utilities	100.00	107.59	119.58	105.74	138.55	140.22

* Assumes investing $100 on 12/31/91 and reinvesting dividends in PP&L Resources, Inc. common stock, S&P 500 Index, and EEI 100 Index of Investor-owned Electric Utilities.

** Effective April 27, 1995, all of the outstanding shares of common stock of Pennsylvania Power & Light Company became shares of common stock of PP&L Resources, Inc. Therefore, through April 26, 1995, these data reflect the total return on the common stock of Pennsylvania Power & Light Company.