Restructuring the Electric Power Industry in New Jersey

Findings and Recommendations

Docket No. EX94120585Y

New Jersey Board of Public Utilities
Herbert H. Tate, President
Carmen J. Armenti, Commissioner

Division of Energy
Robert Chilton, Director

April 30, 1997

NEW JERSEY BOARD OF PUBLIC UTILITIES

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April 1997

Dear Fellow New Jerseyans:

On behalf of the New Jersey Board of Public Utilities, we are pleased to present to Governor Christine Todd Whitman and the State Legislature, as well as all of the residents and business owners in our great State, our findings and recommendations to introduce competition into New Jersey's retail electricity marketplace.

This report represents the culmination of the vision presented by Governor Whitman and the New Jersey Energy Master Plan Committee in the March 1995 New Jersey Energy Master Plan Phase I Report, to transition the State's energy industries away from regulated monopolies towards increased reliance on competitive markets. These policy findings and recommendations to the Governor and Legislature reflect the invaluable assistance and input provided by industry representatives, consumer groups, business and industry representatives, labor unions, energy service companies, independant contractors and environmental advocates throughout our investigation into electric restructuring, which began in July 1995. We express our sincere gratitude to all those members of the public who devoted their valuable time and energies to this investigation.

We are confident that our recommendations to the Governor and the Legislature to offer electric consumers a choice of power suppliers, beginning in October 1998, will provide substantial economic benefit, in the form of lower electric bills and more service options, to the State's residents and businesses. We look forward to working with the State Legislature and the public over the coming months to develop legislation necessary to adopt appropriate consumer protection measures and to implement these policy findings and recommendations.

Very truly yours,

Herbert H. Tate, President

Carmen J. Armenti, Commissioner

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I. Executive Summary

Electric utility rates in New Jersey have consistently been among the highest average rates in the nation for many years. These high rates have not only been a burden on the residents of the State, but have hindered New Jersey's ability to retain and attract business. A reduction in these historically high rates is critical to the ongoing efforts to improve the climate for economic development in New Jersey and to ease the burden on consumers and small business.

For the past several years, New Jersey has been moving toward a restructuring of the State's electric power industry from regulated monopolies to competitive markets. The restructuring of the power industry in the State focuses on increasing competition in both the wholesale and retail markets for three primary reasons: 1) to reduce electric rates for all ratepayers; 2) to expand the choice of services and products for all consumers; and 3) to ensure that New Jersey remains competitive in the regional, national and international markets. It is the State's goal to tap into the burgeoning competitive energy market in the most effective and environmentally protective way possible to reduce generation and production costs.

The introduction of market forces in the electric power industry has the potential to reduce the cost of electricity in New Jersey. The vision of a transition of New Jersey's electric power industry from traditional reliance on monopoly utilities to greater reliance on competitive markets was first set forth in March 1995 with the release of the New Jersey Energy Master Plan Phase I Report by the New Jersey Energy Master Plan Committee, under the auspices of Governor Christine Todd Whitman and Herbert H. Tate, President of the New Jersey Board of Public Utilities (BPU or the Board) and Chair of the Committee.

Beginning with the release of the Phase I Report, the State has embarked on the goal of achieving the vision of increased competition. In July 1995, the State Legislature adopted, and

Governor Whitman signed into law, a Bill that allowed the State's electric utilities to offer electric rate discounts to individual customers under specific extenuating circumstances. This was enacted as a short-term measure to address competitive threats caused by high electric rates, including possible business relocation out of State, with a concomitant loss of jobs, and decisions by in-State customers to build on-site generation and by-pass the native utilities. This new tool provided by the Legislature has been utilized by the electric utilities to help retain businesses in the State employing over 5,400 individuals, and in promoting business expansions creating over 1,300 new jobs.

Since the Summer of 1995, the BPU has been conducting an investigation to consider opening up the electric retail market in the State to competition, to enable all consumers to directly benefit from increased competition, including potential rate reductions. The investigation to restructure the electric power industry was conducted in a proceeding that encouraged public input through both formal hearings and informal mechanisms, such as advisory councils, working groups and negotiating teams.

This report, providing specific findings and recommendations to restructure the electric power industry in the State, represents the culmination of this extensive public investigation. The primary recommendation in this report is the proposal that, in October 1998, retail electric customers in New Jersey will begin to be given the ability to directly choose their electric power supplier, and that by July 2000 all New Jersey retail customers will have the freedom to exercise that choice. This report also recommends near-term electric rate reduction for all customers in the range of five to ten percent, in connection with the phase-in of retail competition.

The BPU believes that the generation function of the electric power industry is no longer a natural monopoly, and that power suppliers can and should directly compete. It is the BPU's judgment that market discipline is best imposed by consumers who can "vote with their feet."

Consumer choice, in conjunction with the necessary consumer protections, will offer ratepayers the ability to tap directly into the competitive power supply market and benefit from lower cost electric services.

A competitive wholesale power market has been developing for several years in the region and across the nation. In May 1995 the Federal Energy Regulatory Commission (FERC) adopted rules which require electric utilities to provide all eligible wholesale power suppliers with access to their electric transmission facilities. This federal action has effectively paved the way for a fully competitive wholesale power market. In addition, a number of states in our region, including Pennsylvania, New York, Massachusetts, New Hampshire, Rhode Island, Vermont and Maine, as well as California, have passed legislation or announced plans that would begin retail choice for electric customers in 1998 or 1999. A number of pilot programs are already underway. Moreover, legislation has been introduced in Congress which, if adopted, would mandate that all states open retail electric markets up to competition by a certain date. As such, it is necessary for New Jersey to act to determine its own destiny now, and to protect and improve its competitive position by providing its electric customers the opportunity to shop for cheaper power.

Concurrent with the proceeding on electric industry restructuring, the Whitman Administration, recognizing the need to lower energy rates, has proposed a reduction of the current energy tax rate by 45 percent over a five year period. The tax revision proposal, released in November 1996, recommends various modifications to the energy tax policies in the State to conform with the changes taking place in energy power markets.

The proposed reforms are intended to level the tax playing field among competitive energy suppliers in the State in both the retail and wholesale markets, as well as to prevent the tax revenue erosion which would result under the current tax laws when retail electric competition is implemented. The proposal recommends replacing the existing Gross Receipts and Franchise

Tax (GR&FT) on utility rates with two taxes, applicable equally to all energy suppliers, as well as a transitional tax (TEFA) paid by all users of the utility distribution system for a limited number of years.

Utilities would pay the State the corporate business tax, as do all other business entities, and the State sales tax of 6 percent would be collected on all retail sales of energy services. The TEFA will be set to ensure that the overall tax revenues collected will remain the same as under the current tax system. A gradual phase-out of the TEFA is proposed over a five-year period, which upon completion, would reduce the total energy tax burden on utility customers by approximately 45 percent. At the completion of this phase-out period, electric rates in the State would be reduced by approximately 6% from their previous levels.

The BPU regards these efforts to reform the existing energy tax essential to the introduction of retail electric competition.

Bills which would put into law the primary components of the energy tax reforms - S.30 and S.31, and A. 2824 and A.2825 were introduced into the State Legislature in March 1997. In addition to forming the energy tax structure the companion bills provide for funding levels and allocation of energy tax revenues to ensure that municipalities are held harmless as the energy tax system is restructured.

In the current electric power industry structure in New Jersey, as across the country, consumers are beholden to the local electric utility, which essentially has a monopoly franchise to sell so-called "bundled" electric service to all customers located within its service territory. Bundled electric service consists of power generation, as well as transmission of electricity through high power lines across state boundaries, distribution of electricity through local power lines, and auxiliary customer services, such as metering and billing. The customer, however, simply sees electricity delivered to the meter at one, bundled price. That price is currently regulated by the BPU.

The BPU concludes in this report that, beginning in October 1998, the costs for those electricity services will be unbundled. The electric utility will continue to be responsible for connecting customers to the system and for providing distribution service to all customers. The price and service quality for distribution service will continue to be regulated by the BPU. The electric utility will also continue to offer customer services for a monthly fee, including metering, billing and account administration, which would also be regulated by the BPU. Transmission service will be provided by an Independent System Operator (ISO), which will be responsible for maintaining the reliability of the regional power grid. This entity will be regulated by the FERC, just as transmission service is today, because power transmission generally occurs as interstate commerce. The local electric utility will pass through the cost of transmission to customers in its regulated rates, as done currently.

Although it is the BPU's proposal to continue utility responsibility for customer services, such as metering and billing, at least for a transitional period, the BPU will form a Customer Services Working Group to further review the issues and make recommendations by July 1998 for the long term related to the introduction of competition into the customer services area.

The BPU also concludes that there is no compelling reason that would preclude a distribution utility from offering customer-side services, such as equipment repair and service contracts, in a competitive marketplace. However, such competitive services offerings by a utility must be subject to strict standards for fair competition. Specific standards, both with respect to the performance of competitive services by electric utilities, as well as the interrelationships between the utility and its affiliates participating in competitive energy services, will be developed within the context of the utility restructuring filings.

The BPU is committed to assuring that a fully competitive marketplace exists prior to the ending of its economic regulation of power supply. At a minimum, utility generating assets and functions must be separated and operate at arms length from the transmission, distribution and customer service functions of the electric utilities. This is best accomplished through the establishment of a separate, affiliated generation company. The BPU reserves final judgment on the issue of requiring divestiture of utility generating assets until detailed analyses of the potential for market power abuses by utilities have been performed. In addition, we believe that it is necessary to have a fully independent and operating ISO, consistent with the FERC's ISO principles, prior to the implementation of customer choice in New Jersey.

It is expected that a Mid-Atlantic region ISO will result from the federal PJM restructuring proceeding. The BPU believes that it is most cost-efficient and appropriate to rely upon a Mid-Atlantic region ISO, that has evolved from the existing PJM power pool, to implement a competitive retail market in New Jersey, at least in the initial stages. An unbiased ISO will ensure continuing reliability of the system, and prevent undue market influence by any individual seller or group of sellers.

The BPU finds that retail competition in New Jersey should be introduced approximately twelve months after the implementation of full wholesale competition, as provided by the FERC's Order 888. The unresolved technical and administrative issues surrounding the transformation to a fully competitive wholesale power market as implemented through an open transmission access system and formation of an ISO, including environmental comparability issues and the reliability of the electric power grid, requires a period of time to resolve the inevitable problems before introducing the additional complexity associated with retail customer choice of electricity supplier.

It is the BPU's firm belief that retail choice must be phased-in over a period of time, but be provided to all customer groups simultaneously. Therefore, each step of the phase-in will provide choice to a cross-section of customers that represents the overall customer mix in each utility's service territory. In keeping with that premise, the proposed timetable for the phase-in of retail choice for all customers in the State is as follows:

Date	% of Total Customer Load
Oct. 1, 1998	10%
Jan. 1, 1999	20%
Apr. 1, 1999	35%
Oct. 1, 1999	50%
Apr. 1, 2000	75%
Jul.. 1, 2000	100%

To further provide opportunity for all customer types to participate in each phase of the introduction of choice, each block of the phase will be expanded an additional 5% to accommodate municipal aggregation and State and County entities.

Each electric utility in the State will be required to file, no later than July 15, 1997, complete restructuring plans, stranded cost filings and unbundled rate filings. Given the interrelated nature of each of the filings, we conclude that it would be most efficient and productive to consolidate all three filings under one proceeding for each of the electric utilities in the State. Review of these filings would be completed by October 1998, when the introduction of retail choice would begin.

An increasing percentage of customers, starting in October 1998, will be able to choose a non-utility power supplier in a competitive market. Customers will be able to sign an agreement with a third party supplier of his or her choice, and the electric utility would be obligated to deliver that power to the customer. The price for power agreed upon between the customer and the third party supplier would be unregulated, and subject to market forces. Customers could also choose to remain with the local electric utility as their full service electric supplier.

To ensure an orderly transition, at least during the initial transition period, the local distribution utility is being assigned the responsibility of providing basic generation service. The electric utility will be responsible for assuring universal service by being available to provide power to all customers in the State who choose to remain with the utility or who are unable to arrange an alternative supplier.

While deregulation and the introduction of competition will provide customers the opportunity to shop for less expensive power, the report also recognizes that there will be an ongoing need to provide consumer protection in the competitive marketplace. Consumer protections recognized in this report include: maintaining the electric utility as a universal service or "basic generation service" provider; and continued funding of social programs now provided by electric utilities, including the winter moratorium program.

In addition, we believe that during the transition period, at the very least, additional customer protections beyond those typical of other non-regulated industries operating in the State are appropriate and necessary. The BPU will form a Consumer Protection Task Force, headed up jointly by the BPU, the Ratepayer Advocate and the Division of Consumer Affairs to work with consumer and industry stakeholders to review existing consumer protection laws and develop specific recommendations, by November 1997 for any revision to the Consumer Protection Act or other legislation or policy initiatives that are necessary to encompass any customer complaints regarding alleged fraud or other acts by power suppliers.

The BPU recognizes that even when price is no longer regulated, a need will remain for a forum for resolving customer complaints regarding pricing of services. In addition, as previously explained, the BPU will still retain full jurisdiction over all aspects of distribution service. The Consumer Task Force will also develop recommendations for a comprehensive consumer education program prior to the introduction of electric power retail competition. Such consumer education will be vital in helping consumers understand the choices being presented to them, and understanding their rights in a competitive marketplace.

As well, the Task Force will develop recommendations regarding the disclosure by power suppliers of the level of air emissions generated by their sources of power supply.

The BPU has determined to preserve the provision and funding for existing social protection programs, including the winter moratorium program, the costs associated with serving "bad debt" customers, low income assistance and weatherization programs. Similarly, we conclude that it is appropriate, at least during the transition period, that existing utility institutions ensure that cost-effective energy efficiency programs be continued. We emphasize that electric utilities having the obligation of implementing social programs, energy efficiency and universal service should not be financially or competitively disadvantaged as a result, and propose mechanisms for timely recovery of these costs by utilities.

A significant issue concerning the transition to a competitive power industry is how to deal with electric utility "stranded costs." These are costs related to generating capacity currently in utility rates, which the utility is at risk of being unable to recover if the supply market is open to competition. Utility stranded costs in New Jersey are driven to a large extent by two factors: the high construction and operating costs incurred by utility-owned nuclear power plants, and long-term (typically 20 to 30 years), high-cost supply contracts with non-utility generators, or independent power producers (IPPs).

This problem is substantial in New Jersey. It has been estimated that electric utility generating capacity and commitments have costs that exceed their market value by anywhere from $7 to $17 billion, depending on the assumed market price for power in the future. Financial write-offs of this magnitude could obviously cause substantial financial turmoil and possibly result in large job reductions at utility companies.

In order to avoid such drastic results, the report proposes that utilities have an opportunity, for a limited number of years, to recover through rates stranded costs associated with generating capacity commitments made prior to the advent of competition. However, while we propose that the quantification of eligible stranded costs and a determination of stranded cost recovery should be undertaken on a case-by case basis, the report recommends that there not be a guarantee for 100 percent recovery of all eligible stranded costs. The opportunity for full recovery of such eligible costs is contingent upon and may be constrained by the utility meeting a number of conditions, including achievement of the goal of delivering a near term rate reduction to customers of 5 to 10 percent.

We believe that an absolute guarantee for recovery of all uneconomical costs may penalize those who have been more successful in controlling generating costs. Furthermore, utilities are obligated to take all reasonably available measures to mitigate stranded costs caused by the introduction of retail competition. Moreover, a guarantee for full recovery may not be consistent with the near term rate reduction goals we have recommended.

IPP contracts, which have been determined by the courts to be largely beyond the jurisdiction of the Board to impose mitigation, must be eligible for stranded cost recovery. However, because these contracts represent such a significant portion of the stranded cost problem, we strongly encourage all stakeholders to explore all reasonable means to mitigate NUG contracts. To date, voluntary negotiations have produced little in the way of improving the pricing terms of these agreements. The FERC, the U.S. Congress and the State Legislature might wish to review this area to provide an added impetus for parties to seriously pursue mitigation of these contracts.

A relatively recent mechanism to help mitigate stranded costs, which the State is studying, and which several other states have authorized to help address the stranded cost issue, is the "securitization" of such costs. This entails the financing of stranded costs, up to a defined limit, through the issuance of debt (asset backed securities or ABS) and paying the interest and principal associated with the ABS through a surcharge levied on the utility's customers. Among other advantages, securitization provides a means of financing at interest rates lower than the utility cost of capital, thereby helping to mitigate the rate impact of stranded cost recovery. Importantly, while the ABS can be issued by either a special purpose subsidiary of the utility or a State agency, with legislative authorization, they would not in any way represent an obligation of the State.

A specific market transition charge (MTC), which would be a separate component of a customer's electric bill, will be established for each utility. This would provide the specific mechanism to allow utilities the opportunity to recover stranded costs for a limited number of years, ranging from 4-8 years from its implementation. Recovery of securitization may occur over a different period of time.

The BPU proposal does not set any specific cost sharing percentage between shareholders and ratepayers for stranded costs. Rather as stated, we prefer setting specific rate reduction targets. The BPU believes strongly in the customers' right to pay just and reasonable rates. Therefore, we have concluded that each electric utility will have a cap imposed on the level of the MTC in order to accomplish the goal that customers experience an overall reduction in rates of at least 5 percent to 10 percent concomitant with the phase-in of retail competition. We believe this percentage reduction is reasonable and can be achieved concurrent with the introduction of retail customer choice, in conjunction with the development of the securitization mechanism, the market transition charge, and stranded costs mitigation measures. We further believe such reductions to be appropriate in light of reductions of similar magnitude which will be occasioned by the State's proposed energy tax policy changes. Combined with the impacts of the proposed modifications to State energy tax policy, the recommendations in this report would produce an aggregate electric rate reduction on the order of at least 10-15%.

The Report suggests the need for federal action in a number of areas as an integral part of electric restructuring. These include the need for the federal government to adopt emission standards that impose similar requirements on generators in the Midwest and Southeast that currently exist for northeastern states; the need to adopt national reliability standards for generators; and the need to establish a clear demarcation of jurisdiction between the FERC and state commissions concerning transmission and distribution service.

Of particular concern is the transport of nitrogen oxides (NOx) and other pollutants to New Jersey and other northeastern states from power plants located in the Midwest and Southeast areas of the United States. The State is concerned that open transmission access in the wholesale energy market, as provided by the FERC in Order 888, could encourage increased electrical generation at power plants in those regions that already contribute significantly to ozone smog problems in New Jersey. The State maintains that safeguards are needed to ensure that open access accomplishes the economic benefits from competition without increases in pollution.

The BPU and the New Jersey Department of Environmental Protection (DEP) filed a motion with the FERC on May 23, 1996 for a rehearing of its rule, pertaining specifically with the Commission's failure to address the mitigation of NOx transport. The State maintains that the air pollution transport problem needs to be comprehensively addressed through a combination of federal and State actions regarding the implementation of the Clean Air Act, and, if necessary, further action by FERC.

The report endorses environmental disclosure by power suppliers as a means of providing consumers with the information necessary to choose cleaner sources of power available in the marketplace; implementation details including the ability to perform verification of claimed emissions rates, will be explored by the Consumer Protection Task Force.

The BPU believes that a combination of the U.S. Environmental Protection Agency (USEPA), and possible FERC actions, along with collaborative state efforts, notably the efforts of the Ozone Transport Advisory Group (OTAG), can effectively safeguard against the potential adverse environmental impacts resulting from open transmission access and also achieve emission comparability. Such actions will better serve New Jersey's interests than unilateral State actions. Therefore, we advocate giving these measures a reasonable opportunity to reduce NOx emissions in upwind states. Secondly, we suggest the need to consider federal legislation to clarify the ability of the USEPA to impose regional or national solutions in the event that collaborative efforts amongst the states prove unsuccessful. However, New Jersey will develop a contingency action plan if federal or regional action fails to mitigate adverse environmental impacts caused by electricity restructuring by October 1998, when retail competition is set to begin.. The BPU, along with the DEP, will explore the establishment of emission portfolio standards applicable to all retail suppliers in the State, as part of such contingency plan.

These findings and recommendations are intended to accomplish the goals of restructuring in a manner that ensures the continuation of service reliability and quality, assures strong consumer protection, protects and creates jobs and businesses, maintains the commitment to social goals currently embedded in bundled electric rates and services, protects the environment, and promotes energy efficiency.

The Board issues these final findings and recommendations on electric industry restructuring in New Jersey and presents them to Governor Whitman and the State Legislature for their consideration. The BPU intends to work with the State's legislators during 1997 to provide the legislative foundation and necessary legal authority for these final findings and recommendations.

II. Background and Introduction

In March 1995, Governor Christine Todd Whitman and Herbert H. Tate, President of the New Jersey Board of Public Utilities and Chair of the New Jersey Energy Master Plan Committee, announced the release of the "New Jersey Energy Master Plan Phase I Report" (Phase I Report). This document presented a vision for the State that was based on energy markets guided by market-based principles and competition. That policy vision departs from over 80 years of traditional regulation, whereby a small number of large, monopolistic, vertically-integrated utilities provide power at regulated rates. In New Jersey, the evolution from regulated to competitive markets is being conducted in a measured transition to ensure fairness and create opportunities for all stakeholders and to enhance energy markets and industries.

Electric rates in New Jersey have, for many years been significantly higher than the national average. These high energy costs have hindered the State's ability to compete for job-creating businesses and have put a burden on consumers. The New Jersey Energy Master Plan Phase I Report recognized that increased competition in New Jersey's energy markets offered the potential to help reduce the high energy prices experienced in the State, support the State's economic development goals, and provide an opportunity to streamline the regulatory review process. In response to federal guidance and market pressures, the Energy Master Plan Phase I Report provided a policy framework for the transition from power industry monopolies to competitive markets.

In addition, the Phase I Report made several policy recommendations to be implemented in the short-term, to address immediate competitive pressures in the State caused by our high energy prices, and to prepare for the transition to competition. These identified measures included passage of legislation providing standards for rate flexibility as an interim measure to allow New Jersey's electric utilities to compete to retain "at risk" customers and attract new customers, and legislation permitting alternative (non-traditional rate base/rate of return) regulation to align the interests of customers and utility shareholders, and to stimulate efficiency and innovation. In addition to the recommendations for interim action to address the changing marketplace and economy, the Phase I Report also explicitly directed the BPU to investigate possible changes to the structure of the electric power industry in New Jersey as a more longer term means of achieving a lowering of the cost of electricity in the State.

In response to the identified need for interim measures, the New Jersey State Legislature acted to supplement Chapter Two of Title 48 of the Revised Statutes, by addressing the need to modify traditional methods of regulation to accommodate the changing marketplace and regulatory landscape. Companion Senate (S-1940) and Assembly (A-91) bills were introduced in the Legislature, sponsored by Senator Joseph M. Kyrillos, Jr. and Senator John A. Girgenti in the Senate, and Assemblyman Richard H. Bagger and Assemblyman William J. Pascrell, Jr. in the Assembly. After amendments to clarify and enhance various consumer protection features, the legislation was passed by overwhelming majorities in both houses of the State Legislature. On July 20, 1995, Governor Christine Todd Whitman signed into law P.L. 1995, c.180, that determined that the BPU should implement programs that promote a transition to a market-based, competitive environment in the energy industries.

P.L. 1995, c.180 (otherwise referred to generally as the "Rate Flex and Alternative Regulation Act" or "the Act") found that during a transitional phase towards competition, it might be necessary for the BPU to implement short-term measures to promote and enhance economic development and employment in the State, and to permit New Jersey utilities to compete for customers with competitive alternatives. The Act specifically allows the State's electric utilities for a period of seven years from the passage of the Act to enter into off-tariff rate agreements with customers under clearly prescribed consumer protection standards. It further permits the utilities to petition the BPU to be regulated under alternatives to rate base/rate of return regulation, subject to strict consumer protection standards.

This new law further declared the policy of the State to foster the production and delivery of electricity and natural gas in a manner that lowers costs and rates and improves the quality and choices of service for all energy consumers. No less important, the intent of the legislation was to ensure that New Jersey remains economically competitive on a regional, national and international basis, and to enhance the economic vitality of the State by attracting and retaining business and creating jobs. The Legislature also found that competitive market forces can produce the stated goals of improved quality and choices of energy services at lower costs, while promoting efficiency, reducing regulatory delay, and fostering productivity and innovation.

Since the passage of the Rate Flex Act, New Jersey electric utilities have implemented, after review by the BPU and the Ratepayer Advocate, 16 off-tariff rate agreements (OTRAs) with individual customers. These discounted rate agreements have played a role in retaining businesses in the State employing over 5,400 individuals, and promoting business expansions creating over 1,300 new jobs.

Consistent with the Phase I Report, and in keeping with the Legislature's stated desire that increased competition in energy markets be explored as a more long term means to reduce the cost of electricity in New Jersey for all customers, by Order dated June 1, 1995 (Docket Number EX94120585), the BPU initiated a formal Phase II proceeding to investigate the long term structure of the electric power industry in the State, and to develop an electric power industry policy that:

* allows a competitive marketplace to determine the quality and price of services where effective competition exists and ongoing regulation is unnecessary to provide consumer protection;

* facilitates the development of competition in those markets where competitive services do not exist, but where increased competition could benefit consumers; and

* continues to regulate the quality and price of commodities and services where competition does not exist and it is determined that consumers are best served by continued regulation.

The fundamental question posed by this investigation was whether, how and when competition should be introduced into the retail electricity market in New Jersey. Similar investigations have been undertaken in many states throughout the country. Indeed, as will be described later, regulators and/or legislators in a number of states, particularly in the northeast, have recently made decisions to introduce competition at the retail level over the next several years.

More precisely, the Proceeding to Investigate the Long-Term Structure of the Electric Industry was initiated by the Board to investigate the appropriateness and feasibility of electricity wheeling or competition at the retail level; the actions necessary to establish a fully efficient, competitive wholesale marketplace for electric generation; whether divestiture of electric utility generation assets is necessary; the need for retail wheeling if an efficient, competitive wholesale electric power market is achieved; the need for divestiture of electric utility generation assets or alternatively, the unbundling and corporate separation of electric services; and the definition, and equitable treatment for stranded investments.

The Order specifically directed that the Proceeding investigate the appropriate manner of continuing existing consumer and environmental protections in a restructured market; ensuring universal, non-discriminatory access to service; a safe and adequate power supply and system reliability; and achieving the State's environmental and energy efficiency goals. These are all State policy goals found within P.L. 1995, c.180.

Public Participation

Over the course of the past 21 months since the BPU launched this investigation, we have sought through numerous means to obtain guidance and input on the many complex issues raised from the widest possible array of interests. The interest groups that have been represented in this investigation include commercial and industrial users, consumer advocates, electric utilities, energy service companies, environmentalists, gas utilities, independent power producers, labor unions, local and county government, municipal and cooperative utilities, plumbing, heating and cooling contractors, and power marketers.

As described in detail in **Appendix 1**, the BPU has solicited and received several rounds of written comments as well as written testimony, conducted both public and legislative-type hearings and, through its Staff, formed and facilitated informal working groups and a negotiating team to explore issues in depth. Indeed, as part of this effort, in May 1996 the BPU approved the release of a Status Report prepared by the BPU Staff. The Status Report, based upon the reports developed by four technical working groups, provided a detailed discussion of the important issues surrounding electric restructuring and the status of discussions. On January 16, 1997 the BPU released its Proposed Findings and Recommendations in this matter, and written comments were solicited and public hearings conducted to provide public input on this policy proposal. The attachments to this report provide details on the public process followed by the BPU, and provide detailed summaries of the positions taken by the parties and public commentators in this proceeding.

Having carefully considered all of the input received in this investigation, the BPU is now prepared to issue its final findings and recommendations concerning the future structure of the electric power industry in New Jersey, set forth in the following sections of this report. It is the BPU's intent to submit our final findings and recommendations to the Governor and the Legislature for their consideration. In the hope that the Legislature concurs with our vision for the future structure of the electric power industry in New Jersey, we look forward to working with the the State's legislators during 1997 to craft legislation which will provide the foundation and necessary legal authority for the changes we recommend.

III. Current Electric Industry Structure and Rates In New Jersey

The current structure of the electric power industry in New Jersey is basically the same as it has been since the early years of this century. Traditional, vertically-integrated public utility companies, with defined service territories, serve approximately 98% of the retail electric load in the State[1]. Vertically-integrated companies have ownership of power generation plants, as well as transmission, distribution and customer service facilities. Retail electric customers in a particular geographic location are by and large beholden to the local electric utility company for what is referred to as "bundled" electric service. Bundled electric service means that the electric utility essentially provides a package of services which, to the consumer, appears as one service billed at a single price. The different individual services that the utility actually provides as part of its "bundled" service include: power supply, electric transmission and distribution service, as well as customer services such as service connects and disconnects, metering, billing and account administration. In return for the granting of an effective monopoly in a franchise area, electric utilities are obligated to provide service to all customers requesting service, and are subject to price and service quality regulation by the New Jersey Board of Public Utilities.

This industry structure historically served the State, and the nation at large, quite well. The cost-based regulation regime, which provided an opportunity for a fair and reasonable rate of return on prudently incurred utility plant capital investments, provided the backdrop for the development of a reliable and extensive electric production and delivery infrastructure. Today, electricity service is available to virtually every residence and business in the State and, despite occasional short-term power interruptions due to extreme weather or equipment failure, the

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[1] The other 2% of retail load is served by the nine municipal utilities in the State and one rural electric co-op.

reliability of power grid is unmatched anywhere in the world. Moreover, up until the 1970's, electric utility rates in the State were relatively stable or even for some periods declining, reflecting technological developments and economies of scale.

However, from the 1970's forward, rates have increased steadily and in some instances dramatically. As shown in Table I below, by 1985 the average electricity prices paid by New Jersey consumers were approximately 50% above the national average price for electricity. Virtually the same price disadvantage persists today, with electric customers of all classes in New Jersey still paying on average upwards of 50% higher than the national average electricity price.

Table I

Retail Price of Electricity Sold by Electric Utilities[2]

New Jersey vs. National Average

(Cents per Kilowatt-hour)

Year	Residential	Commercial	Industrial	All Sectors	Percent Difference
1985 Nat'n Avg.	7.39	7.27	4.97	6.44	
1985 NJ	11.00	9.60	8.00	9.60	49%
1995 Nat'n Avg.	8.42	7.70	4.69	6.90	
1995 NJ	12.00	10.20	8.30	10.40	51%

[2] Source: Electric Sales and Revenues 1994 DOE/EIA-0540(94)

As shown in Table II below, these rates put New Jersey near the top of the list of electric prices nationally, along with neighboring regional states such as New York and in New England, as well as California.

Table II

1994 National Rates Survey

Average Price (cents/Kwh)

State	All	Residential	Commercial	Industrial
New Hampshire	11.32	12.91	10.91	9.32
New York	10.92	13.55	11.67	6.77
Hawaii	10.68	12.45	11.67	8.82
Alaska	10.25	11.32	9.66	8.37
Rhode Island	0.24	11.26	9.95	8.86
Connecticut	10.18	11.47	9.99	7.90
New Jersey	**10.06**	**11.54**	**9.84**	**7.94**
Massachusetts	10.00	11.09	9.75	8.46
California	9.78	11.43	10.90	7.09
Maine	9.63	12.32	10.16	7.18
Vermont	9.13	9.96	9.42	7.50
Arizona	7.93	9.30	8.32	5.63
Pennsylvania	7.87	9.55	8.28	5.93
Illinois	7.41	9.98	7.68	5.18
Dist. of Col.	7.12	7.47	7.15	4.63
New Mexico	7.11	9.14	8.30	4.70
Michigan	7.09	8.28	7.93	5.25
Maryland	7.03	8.39	7.19	5.30
Florida	6.96	7.78	6.35	5.13
Delaware	6.78	8.91	7.00	4.62
North Carolina	6.62	8.17	6.56	4.93
Kansas	6.61	7.89	6.66	4.93
Georgia	6.57	7.72	7.33	4.57
Texas	6.42	8.08	7.04	4.27
Nevada	6.37	7.16	6.97	5.45
Arkansas	6.35	8.07	6.88	4.60
Missouri	6.28	7.29	6.20	4.62
Virginia	6.20	7.75	5.84	4.16
South Dakota	6.19	7.06	6.60	4.51
Ohio	6.19	8.56	7.72	4.14

Colorado	6.07	7.36	6.00	4.58
Mississippi	6.05	7.06	7.22	4.48
Louisiana	6.05	7.61	7.20	4.22
Iowa	5.92	8.09	6.32	3.88
Oklahoma	5.84	7.03	6.09	4.07
North Dakota	5.77	6.37	6.45	4.71
South Carolina	5.67	7.49	6.37	4.03
Minnesota	5.63	7.16	6.25	4.41
Nebraska	5.49	6.31	5.58	3.99
Alabama	5.48	6.69	6.76	4.12
Wisconsin	5.46	7.08	5.87	3.89
Utah	5.36	6.91	5.87	3.83
West Virginia	5.25	6.36	5.83	3.98
Indiana	5.25	6.78	5.91	3.97
Tennessee	5.23	5.88	6.63	4.52
Oregon	4.60	5.33	4.97	3.47
Montana	4.51	5.96	5.17	3.30
Kentucky	4.26	5.77	5.29	3.24
Wyoming	4.26	6.04	5.02	3.51
Washington	4.02	4.97	4.72	2.79
Idaho	4.00	5.09	4.37	2.82

Indeed, as shown in **Appendix 2**, other than the New England states, New York and California, electricity rates in New Jersey compare quite unfavorably with every other region of the country. Perhaps the most unfavorable comparison is with the Southeastern U.S., where average electricity prices are nearly half those paid by New Jersey consumers. Even within the Mid-Atlantic area, New Jersey consumers pay, on average, 30% above the average regional electricity rate.

To some extent the relatively high prices which have persisted in the State are due to generic factors we share with the other identified high cost states, including such factors as a generally higher cost of living, higher energy taxes, tighter environmental standards and a lack of indigenous energy supplies such as coal or natural gas. Indeed, as summarized in Table III below, it shows that New Jersey has one of the highest energy tax rates in the country.

Table III

Comparison of Energy Taxes[3]

(as a percentage of revenues)

State	Electric	Natural Gas
New York	16.5%	7.9%
New Jersey	**12.4%**	**12.8%**
Ohio	12.2%	7.7%
Indiana	11.8%	4.7%
N. Carolina	10.5%	5.4%
Georgia	8.3%	2.3%
Pennsylvania	8.3%	3.0%
California	8.1%	2.5%
Texas	6.7%	2.6%
Virginia	4.3%	3.0%

However, a specific relevant circumstance we share with other high-priced states in the Northeast and with California, which substantially influences overall utility costs, is high average power production costs. As indicated in the Status Report, New Jersey utility average power production costs, at over 6 cents per kilowatt-hour, are approximately 50% higher than the national average. Indeed, production costs alone for New Jersey utilities equal or exceed the total (i.e. bundled- including the cost of production, transmission, distribution and customer service) average utility rate experienced in many States in other regions of the country. As set forth in the Status Report, the primary cause for high

[3] Source: Joint Task force Report on Energy Tax Policy, Presentation for the League of Municipalities, November 20, 1996

average production costs in New Jersey are relatively expensive utility-owned nuclear power plants and relatively high-priced power purchase agreements with non-utility generators (primarily cogeneration facilities) and, to a lesser extent, utility-owned fossil fuel-fired power plants.

Efforts to reduce these historically high costs of electricity in New Jersey are critical to the ongoing efforts to improve the climate for economic development and the creation of good, high-paying jobs for our residents. Lower electric rates would also ease the burden on consumers and small businesses trying to make ends meet. This same sentiment is fostering the move in other high electric cost states, particularly in the Northeast and in California, to restructure the electric power industry on an aggressive timetable.

As described in the Status Report, over the past 15 years or so, competition has gradually permeated the production end of the industry. The passage of the federal Public Utility Regulatory Policies Act (PURPA) in 1978 provided the impetus for the development of what is today a thriving cogeneration and independent (i.e., non-utility) power production industry (currently approximately 19% of the electricity consumed by the New Jersey utility customers is purchased from independent power producers). The federal Energy Policy Act of 1992 (EPAct) further promoted the introduction of competition in the wholesale power market by giving the FERC the authority to order that transmission-owning utilities provide third party suppliers with access to the wires. Most recently, in November 1996, the FERC issued final rules (Orders 888 and 889) requiring that each transmission-owning utility develop and implement open access transmission tariffs. FERC Order 888 requires transmission-owning utilities to provide third party producers and suppliers the same (non-discriminatory) access to the transmission facilities as their own production facilities enjoy.

As a result of these actions and developments, there is an ever-growing number of power producers and suppliers offering power for sale in the regional market, and certainly there is no longer a basis to rely solely on the local electric utility companies to produce the power consumed in the State. It is our ultimate goal to tap into this burgeoning competitive market in the most effective way possible in order to reduce production costs to ultimate end users in the State, and thereby reduce the costs of electricity to consumers in the State.

IV. Restructuring and Competition

A. The Changing Landscape in the Electric Industry

As indicated earlier, federal and state regulatory actions and technological advances have fostered changes that dictate that power production is no longer a natural monopoly function. Indeed, we concur with the Staff's observation in the Status Report that growing competitive forces in the regional bulk power market have already been shown to produce lower energy costs. We have seen in recent years, through competitive solicitations, the offering of bulk power supplies to utilities in the State and the region at prices quite favorable relative to the current cost of production. However, these solicitations have primarily addressed incremental short and mid-term resource needs of the involved utilities. As a result, benefits to New Jersey utility retail customers of these improved bulk power market conditions have been limited to date. This is primarily due to the fact that production costs embedded in retail rates reflect relatively high cost existing long-term commitments as mentioned earlier, including the fixed cost recovery of utility-owned generation plant, and the costs associated with long-term supply contracts with non-utility generators, which cannot be readily displaced in the short term.

We expect the advent of open access transmission, through the implementation of FERC Order 888, to further enhance the development of a fully competitive bulk power market in the region (as well as nationwide), including the proliferation of active sellers in the marketplace. Sellers in the bulk power marketplace include utilities with owned generation plant, non-utility plant owners, power marketers and brokers. As noted in the Status Report, the FERC has estimated national cost savings resulting from full wholesale competition of from $3.8 to $5.4 billion. Accordingly, subject to the issues raised in our Motion for Rehearing and Reconsideration before the FERC, we fully support the transition to a fully competitive bulk power market.

However, we believe, the FERC's estimate of savings does not take into account, the existing, relatively high-cost production costs built into retail electric rates. As noted above, these represent in many instances long-term commitments, either via power purchase agreements or capital investments, which cannot simply be "assumed" away. Moreover, were the development of a competitive marketplace to stop at the wholesale level, retail customers would remain captive to a single, monopoly supplier of power: the local electric utility, which albeit would presumably procure supplies in the open wholesale market for resale to its captive retail customers. First, we do not believe such a market structure to be tenable in the long term. All industries that have preceded the electric power industry on the road from regulation to competition have evolved or are evolving to allow for competition down to the retail level.

Moreover, it is our judgment that, to the extent that a fully competitive power supply market develops and exists, market discipline is best imposed on the utility, as well as other power suppliers, if customers have a choice of suppliers and thereby can effectively "vote with their feet." This view is consistent with the finding of the Legislature in P.L. 1995, c.180 that competitive market forces can produce improved quality and choices of energy services at lower costs. In short regulation, no matter how well intentioned, cannot replicate the results of a competitive market.

Accordingly, it is our conclusion that a restructuring of the electric power in New Jersey is necessary to tap into the growing competitive forces in the industry and to address the current high level of electric rates in the State. This will encompass initially the development of a fully competitive wholesale market consistent with the policies of the FERC. Too, utility "bundled" rates and services will also have to be unbundled in order to separately identify the competitive production function.

It is further our conclusion that the ultimate goal of this restructuring is to provide for competition at the retail level. Such a change, when implemented with the necessary consumer protections in place, will offer all consumers in the State the ability to tap directly into the competitive power supply market and thereby receive lower cost electric services.

This same conclusion has been reached in a number of states in our region, as well as in California. As described below, the identified states have, either through the passage of legislation or via state PUC proposals or findings, or both, made decisions to open up retail markets to competition, and thereby to provide retail consumers with the freedom to choose their power supplier. Virtually without exception, the states which have taken that aggressive step share with New Jersey similar high levels of electricity rates previously discussed. It is therefore now important for New Jersey to act to provide similar opportunities for consumers in the State, in order to improve our competitiveness relative to these surrounding states.

Following is a brief summary of the recent actions taken in surrounding states to begin the introduction of retail electric competition.

In a final Opinion and Order issued in May 1996, the New York Public Service Commission PSC announced a proposed timetable for the transition to competition, including the introduction of a competitive wholesale power market in the state in 1997, and the beginning of retail competition starting in "early 1998." In March 1997, several of the State's electric utilities entered into restructuring agreements with PSC's Staff. These restructuring agreements have been filed with the PSC and are in the process of being reviewed by their assigned Administrative Law Judges. A final PSC decision will be issued shortly after the Administrative Law Judges issue their recommended decisions.

In May 1996 the Massachusetts Department of Public Utilities (MDPU) issued proposed rules proposing that the state's electric utilities implement unbundled rates in

1997, and that retail competition begin in January 1998. Four utilities have filed proposed restructuring plans. On December 30, 1996 the MDPU issued a comprehensive Electric Industry Restructuring Plan, including a legislative proposal, which maintains the January 1, 1998 date for implementation of retail customer choice. On February 24, 1997, Governor Weld submitted proposed restructuring legislation to the Massachusetts legislature.

In May 1996 New Hampshire Governor Merrill signed into law the Electric Restructuring Act. The act requires the Public Utility Commission -NHPUC to implement retail customer choice of suppliers for all electric customers by January 1998; if circumstances require retail competition can be delayed until no later than June 30, 1998. Also in May 1996, a two-year retail pilot program was begun in New Hampshire, whereby 17,000 retail customers were given the opportunity to purchase electricity in the competitive market on an experimental basis. The NHPUC issued its Final Plan, which calls for the implementation of retail competition in 1998, on February 28, 1997. On March 21, 1997, the United States Federal Court in Rhode Island issued a temporary restraining order which freezes implementation of the NHPUC's Final Plan with regard to the State's largest electric utility -- Public Service of New Hampshire.

In August 1996 Rhode Island Governor Almond signed into law the Utility Restructuring Act. The act provides for the following timetable for the phase-in of retail electric competition: starting in July 1997 for existing large industrial customers, new medium and large-size commercial and industrial customers, and all State of Rhode Island accounts; and starting in January 1998 for all existing mid-size industrial customers and municipal accounts. Within three months after at least 40% of New England electric sales is opened to competition, the act requires that all remaining Rhode Island customers have access to competitive suppliers.

In December 1996, Pennsylvania Governor Ridge signed state electric restructuring legislation into law. The act calls for retail competition pilot programs to begin in April 1997, covering five percent of the state's electric sales. Full access to competitive suppliers will be provided to all customers in the state under the following phase-in schedule: one-third of all customers eligible beginning in January 1999; two-thirds of all customers eligible starting in January 2000; and 100% of customers eligible beginning in January 2001.

In December 1996, the Vermont Public Service Board (VPSB) issued an Order which concluded that direct access for all customers should be permitted on a scheduled phase-in starting in early 1998. The VPSB held that the phase-in should be conducted in a manner that does not favor any one customer or customer class. It further held that a "lengthy transition to direct access would also raise some fundamental equity concerns for consumers", it therefore concluded that the phase-in should be completed by the end of 1998.

In December 1996 the Maine Public Utilities Commission issued a Report and Recommended Plan that calls for retail choice for all customers, regardless of size, type or location, beginning on January 1, 2000.

In December 1995 the California Public Utilities Commission (CPUC) issued a final restructuring Order. Subsequently in September 1996 Governor Wilson signed a bill which established as state law, with some modification, the restructuring policies adopted by the CPUC. The act provides for a five-year-phase-in of retail competition for all customers, beginning in January 1998 and being completed by the end of 2002. The law further requires that residential customers receive a 10% rate reduction in January 1998, and another 10% reduction by 2002. An administrative Law Judge has issued a proposed decision which recommends, among other things that direct access should be made available to all California electricity consumers on January 1, 1998, regardless of customer class or size of load. The CPUC is expected to rule on the proposed decision in April 1997.

All of the states described above face the same complex issues relating to their proposed aggressive implementation schedule as faced in New Jersey, as will be described later in this report.

In addition to these individual state activities, there is increasing activity at the federal level concerning the introduction of retail electric competition. Currently, there is no federal authority over retail electric markets. Decisions concerning the sale of power by public utilities to retail customers, and whether to open these markets, is left to the state public utility commissions and legislatures. However in 1996, several pieces of legislation were proposed or introduced which would mandate by a date certain that all states in the nation open up retail electric markets to competition. For instance, Representative Schaefer of Colorado introduced a bill that would require all states to introduce retail electric competition by the year 2000. It is expected that during the 105th Congress this issue will be taken up and debated in earnest. While the state utility commissions, through resolutions adopted by their national organization, known as the National Association of Regulatory Utility Commissioners (NARUC), have urged Congress not to pass a "date certain" mandate for the implementation of retail competition and to leave the details and timing of these decisions to the states, the outcome of this debate is uncertain.

With the various state activities ongoing in our region, it is important that New Jersey move forward on this issue in a timely manner in order to protect and improve our competitive position. Moreover, in light of uncertainties regarding the passage of federal legislation in the 105th Congress, it is in the State's interests to take the initiative at this time and, to the extent possible control our own destiny, by developing now a specific timetable and conditions for the implementation of retail electric competition in New Jersey that best serves our citizens.

Set forth in the following sections are our final findings and recommendations as to the specific industry structure and the timing for the transition to a competitive retail market in New Jersey. As will be described, these are intended to accomplish the goals of restructuring in a manner that ensures the continuation of service reliability and quality, assures strong consumer protection, protects and creates jobs and businesses in the State, maintains the commitment to social goals that are currently embedded in bundled electric rates and services, protects the environment, and promotes energy efficiency.

B. Wholesale Competition

Approximately 95% of the State's electric consumers receive power from either Public Service Electric and Gas (PSE&G), Jersey Central Power and Light (JCP&L)[4], or Atlantic Electric (AE), which are members of the Pennsylvania -- New Jersey -- Maryland (PJM) power pool[5]. The PJM power pool is a voluntary association of eight member electric utility companies in the Mid-Atlantic region, originally formed decades ago. It is the largest, and among the most highly integrated power pools in the country. Under the historic structure of the power pool, the member companies jointly own and control the

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[4] In September 1996, JCP&L combined with its two sister utilities in Pennsylvania and is now doing business in the State under the name GPU Energy.

[5] Approximately 3% of New Jersey's retail customers, located in a relatively small section of northernmost New Jersey, are served by Rockland Electric, a subsidiary company of Orange and Rockland Utilities company located in New York State. Another 2% of retail load in the State is served by the municipal utilities or rural cooperatives.

bulk power transmission system in the region, and jointly plan transmission system upgrades. The PJM agreements and transmission rates charged by the PJM are regulated by the FERC. By virtue of their mutual contractual agreements, the member utilities coordinate generation/supply planning. This is done generally by aggregating the customer load forecasts of all member utilities, calculating an appropriate reserve margin for the entire regional control area, and assigning specific reserve margins for each member utility. Each utility is then responsible for having sufficient installed generating capacity, including owned power plants and firm power purchase agreements, to meet its individual assigned reserve margin. The PJM power pool is operated essentially as one system, whereby the generating units of all member utilities is subject to central dispatch, from order of lowest operating cost to highest cost. The PJM member utilities, through their agreements, also undertake coordinated emergency planning and are bound to mutual support during times of actual system emergency.

The PJM power pool members, along with the installed generating capacity of each, are as follows:

PJM Company	**1996 Installed Capacity (MW)**[6]
Atlantic Electric Company	2,643
Baltimore Gas and Electric Company	6,772
Delmarva Power & Light Company	3,300
General Public Utilities	9,632
Jersey Central Power & Light Co.	
Metropolitan Edision Co.	
Pennsylvania Electric Co.	

[6] Source of data is PJM Supporting Companies Restructuring Proposal to the FERC dated July 24, 1996. Volume III, Attachment XIII, Exhibit 3, Schedule A.

PECo Energy Company	8,952
Pennsylvania Power & Light Company	8,112
UGI Corporation	
Potomac Electric Power Company	6,801
Public Service Electric and Gas Company	10,925
Total PJM	57,137

The PJM power pool, as described above, is generally regarded as having provided substantial benefits to electric consumers in the region, in terms of both enhanced system reliability and economic savings totaling in the billions of dollars. However, the current structure of the PJM power pool is premised on the historical industry structure of vertically-integrated electric utilities. This structure is not suited to a competitive generation marketplace. Indeed, as part of its Order 888, the FERC directed that power pools such as PJM develop and file for review and approval restructuring plans that would accomplish the goals of the FERC's Open Access rule.

The existence of the highly integrated PJM power pool, along with its described benefits, puts the Mid-Atlantic region in a somewhat unique position, and underscores the need for regional cooperation as we move to restructure the electric power industry. Through the leadership of the BPU and other regional agencies, the Mid-Atlantic state regulatory commissions have been engaged in collaborative discussions concerning the ongoing efforts to restructure the PJM power pool. Indeed, the commissions have formulated and submitted various joint comments to the FERC over the past two years emphasizing that the federal open access transmission rules must not undermine the existing reliability and economic benefits for retail customers emanating from the pool.

In order to move to a more competitive wholesale power market, the Status Report released in May 1996 contained a joint recommendation among the parties for certain fundamental changes to the regional power grid, as follows:

1) The current PJM power pool should be changed to allow for expanded membership;

2) There must be a shift from a cost-based to a market-based wholesale market;

3) The PJM power pool should be restructured into an Independent System Operator (ISO);

4) Non-discriminatory transmission tariffs should be filed to provide the appropriate transmission services; and

5) The wholesale market must be designed to assure that utilities do not have a bias to provide capacity or energy from facilities which they own, but which may not be in the best interest of customers.

We concur with these recommendations and, to the extent these issues related to wholesale competition are within our jurisdiction and purview, would adopt and include them as reasonable standards for review of wholesale competition mechanisms, or would otherwise include them as benchmarks in our assessment of proposals before the FERC.

In response to the FERC's directive, the member companies of the existing PJM power pool submitted two competing proposals (one supported by Atlantic Electric, Baltimore Gas and Electric, Delmarva Power and Light, GPU Energy, Potomac Electric Power and Public Service Electric and Gas, otherwise referred to as the "Supporting companies," filed in July 1996; and one supported by Philadelphia Electric, filed in August 1996) for restructuring PJM to introduce open access transmission and otherwise implement FERC

Order 888.

While there were a number of important differences in both concept and with respect to important details between the two proposals, one point of commonality (among certain others) is the proposed establishment of an Independent System Operator (ISO).

Generally speaking, an ISO is an entity not affiliated to any market participant, which independently and without discrimination or bias, operates the transmission system in order to ensure fair and open access to transmission for all suppliers and thereby ensure that a competitive power market exists. The formation of such an entity is necessary in order to ensure that transmission-owning electric utilities, which also own generating assets competing in the supply market, do not gain an unfair competitive advantage.

The Status Report contained a consensus recommendation with regard to appropriate standards to guide the formation and structure of the ISO, that:

1) The operation of the transmission network must be separated from any commercial interest of any one owner of the network, or other users of the network;

2) Non-discriminatory tariffs for provision of transmission services within and through the regional transmission network should be developed;

3) The ISO should be fully independent and operate in accordance with FERC approved tariffs;

4) The ISO should have all necessary operational control over the utilities' transmission system;

5) The ISO should have the ability to contract for identifiable market-valued ancillary services;

6) The ISO should monitor all transactions and any deviations from quantities nominated by participants. The ISO should charge for the use of the

transmission network, for the supply of ancillary services and for any balancing services on the basis of tariffs approved by FERC. To the extent possible, other suppliers should be given the opportunity to provide ancillary services;

7) The ISO should have the responsibility for transmission expansion planning and maintenance planning;

8) To assure reliability, all appropriate market participants will be responsible for meeting reliability requirements; and

9) The ISO decision-making process, and information on its planning and day to day operations, must be publicly available on a full and non-discriminatory basis.

We concur that these standards, at a minimum, are appropriate to apply in assessing the PJM or other ISO proposal.

It should be emphasized that final approval of a regional ISO rests with the FERC, which has jurisdiction over transmission facilities. In its Order 888, the FERC sets forth 11 specific principles for an ISO, which will guide its review of such proposed entities **[See Appendix 3]**.

While the two competing PJM restructuring proposals submitted to the FERC by the member utilities differed in many ways, there were three major areas of disagreement: 1) transmission pricing: the PJM supporting companies supported the implementation of zonal pricing, while PECo supported one postage stamp rate throughout the region; 2) congestion charge: the PJM supporting companies sought the implementation of locational marginal pricing while PECo supported spreading the cost of congestion management to all users through inclusion in transmission rates; and 3) industry model: the PJM supporting companies sought to greater reliance on a centralized power exchange than did PECo.

By an Order dated November 13, 1996, the FERC directed the ten member utilities to revise their competing proposals and encouraged them to work together to craft a single new ISO proposal, finding that both proposals failed to meet various principles in its Order No. 888, most particularly the requirement that ISO be truly independent, and that transmission pricing not be unduly discriminatory. Moreover, the FERC directed that the PJM member utilities, in retooling their proposal(s), provide opportunities for input from non-member stakeholders.

Indeed, representatives of the BPU, along with other Mid-Atlantic state agencies and numerous other industry stakeholders, attended a series of meetings during December 1996 aimed at developing a single PJM restructuring proposal consistent with the directives of the FERC. On December 31, 1996, a single revised proposal was submitted to the FERC for its consideration. However in that proposal, a number of issues were left still unresolved, with alternative approaches left for the FERC to decide. The various stakeholders to the PJM restructuring process have been meeting on a regular basis in Washington D.C. in an attempt to develop a consensus compliance filing for a permanent restructuring of the PJM power pool, which is due to be filed with the FERC by May 31, 1997. For the interim period, the FERC has approved PJM open access, transmission tariffs, effective April 1, 1997, incorporating the supporting companies' proposal with respect to all issues except for congestion pricing.

While some of the specific ISO functions are still undetermined pending a final decision by the FERC with regard to the PJM restructuring proposal, we do expect that a Mid-Atlantic region ISO will result from the PJM restructuring proceeding. Further, we believe it appropriate with respect to the operation and reliability of the regional transmission grid that a regional ISO transformed from the existing PJM power pool be utilized. It is assumed for purposes of this report that all interested parties, including this agency, will have full opportunity to air their positions before the FERC, and that the final

FERC decision will provide for a MAAC region ISO which provides for non-discriminatory open access to the regional transmission grid in a manner which imparts preference towards no interest or market player. This approach, of restructuring the current PJM power pool, as opposed to the formulation of a "from scratch" ISO, will not only build upon the reliability and economy benefits of the existing PJM system, but will also avoid a costly and unnecessary duplication of existing expertise and infrastructure.[7] As will be addressed below, we further believe it to be most cost-efficient and otherwise appropriate to rely upon a Mid-Atlantic region ISO evolved from the existing PJM power pool, at least initially, to implement a competitive retail market in New Jersey[8].

C. Introduction of Retail Competition in New Jersey

Certain parties to this proceeding have articulated a point of view that retail competition be implemented on a very aggressive timetable, some even advocating the simultaneous implementation of full retail and full wholesale competition. Other parties, most particularly the utilities, have asserted that a fully competitive wholesale market is a necessary precursor to retail competition, and that retail competition should not be implemented before there is sufficient time for wholesale competition to mature.

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[7] We note that in California, where no current power pool mechanism exists, several hundred million dollars has been budgeted to develop an ISO and power exchange infrastructure largely "from scratch."

[8] As indicated earlier in this report, Rockland Electric Company (RECo) is a subsidiary of Orange and Rockland Utilities, which is a member of the New York Power Pool (NYPP). The NYPP is currently engaged in a process similar to that described for PJM to restructure the pool into an ISO entity. We envision that competitive retail electric sales in RECo territory will be implemented through an ISO evolved from the NYPP.

We concur with the Staff recommendation contained in the Status Report that retail competition not be introduced simultaneous with the implementation of full wholesale competition as provided by the FERC's Order 888. The reliability of the electric power grid is a critical element of the well being of the State's residents and economy. As we have already seen with the PJM restructuring filings, the technical and administrative issues surrounding the transformation to an open transmission access regime and the formation of an ISO for the purpose of implementing a fully competitive wholesale market, while certainly not insurmountable, are complex. This marketplace restructuring envisions transactions estimated in the hundreds daily. We believe it a wise and prudent approach to allow a period of time for this new marketplace, once approved and fully implemented, to mature and work out the inevitable kinks before introducing the additional complexities associated with supplier choice for retail customers, numbering many times the quantity of wholesale market participants. It is worth noting that in other industries in which the Board has oversight, specifically telecommunications and natural gas, the transition to competition has taken place in stages over a number of years, and indeed is still not complete.

We emphasize on the other hand that, many lessons have been learned from the deregulation of these other utility industries, and the time frame for the transition from full regulation to full competition down to the smallest retail customer need not be identical. Indeed, given the substantial economic benefits which we believe electric power retail competition can provide to the State's residents and businesses, the transition from full wholesale competition to full retail competition should be thoughtful, yet ambitious.

Accordingly, as will be described in more detail below, it is our conclusion at this time that the introduction of retail competition in the State should commence no later than October 1, 1998, and be phased-in such that all customers will have the freedom to choose their power supplier by July 2000.

Implicit in this timetable is our assumption that a PJM wholesale restructuring plan will be approved by the FERC some time in 1997, hopefully by no later than October. Accordingly, this would allow for an approximate one year period for the regional ISO and wholesale power market to be implemented and "debugged" prior to the overlay of retail competition. In either case the phase-in schedule, also provides a graduation which will allow the potential problems in the wholesale market to be fixed with only slight intrusion. Moreover, we believe, this would allow, sufficient time for the Board to conduct necessary proceedings, for the Legislature to take necessary action, and for the technical and administrative details and consumer protection and education programs related to a transition to a competitive retail market, as described below, to be worked out and put in place, prior to the anticipated "roll-out" of retail competition.

This timetable for the introduction of retail competition in New Jersey, as well as the schedule for the phase-in of full competition as will be discussed below, also comports quite closely with the time-frame for opening up retail electric markets adopted in surrounding states, described previously. Not only will this maintain New Jersey's competitive position, but it will also hopefully mitigate against significant reciprocity problems between neighboring states.

D. Potential Environmental Impacts from Competition

A significant issue which has arisen within the context of both wholesale and retail electric competition relates to the transport of nitrogen oxide and its affect on New Jersey's air quality. Nitrogen Oxides (NOx), when combined in the atmosphere with volatile organic compounds (VOCs) produce a photochemical reaction, which results in the formation of ozone, which has been determined to have negative environmental and health impacts. New Jersey, along with other Northeast states, is currently not in compliance with national ambient air quality standards for ozone.

New Jersey's non-compliance with ambient air standards is in part due to the density of the State, and its numerous mobile and stationary sources of ozone precursor emissions. However NOx emissions from large sources located even hundreds of miles outside the State, through atmospheric transport, also contribute to the degradation of air quality in New Jersey. There is the concern that the restructuring of the power market to provide open transmission access and increased competition will encourage increased electrical generation from older, low-costs power plants in the Midwest and Southwest regions of the country. These power plants generally operate with pollution control requirements much less stringent than those imposed on plants located in New Jersey. Such an increase in generation would result in an increase in levels of NOx emissions from these generating plants, that already contribute significantly to the air quality problems in New Jersey. As will be described in more detail in a later section of this report, this could result in a substantial increase in NOx emissions being transported into the Northeast by prevailing air currents, causing additional environmental clean-up costs and more stringent EPA Clean Air Act compliance measures for states such as New Jersey.

There has been much debate within the industry regarding the appropriate mitigation, if any, of these environmental issues related to electric restructuring. New Jersey's position on this critical issue was expressed by Governor Christine Todd Whitman in a letter to the FERC dated January 19, 1996, asserting that mitigation of these impacts is vital to the interests of the State. We will address this issue in more detail, and make specific recommendations, in Section VIII.C. of this report.

V. Retail Market Structure

A. The Need To Unbundle Electric Service

As described earlier in this report, consumers have for decades received what we have referred to as "bundled" electric service at one price. This bundled service actually has encompassed a number of discrete services. Because utilities have operated as vertically-integrated, regulated monopolies, these discrete services have been virtually indistinguishable to the consumer. The consumer receives one package of delivered power to the meter. That package of "bundled" power services is delivered at a price which is regulated by the BPU, based upon the cost of providing service.

As competition is introduced into various sectors of the electric industry, these services will have to be separately identified and billed. Particularly, competitive services will have to be separated from those which will continue to be provided on a monopoly basis by the electric utilities, in order that customers may be able to clearly identify where they have the ability to choose. The separate services that are currently encompassed in "bundled" electric utility service and rates include generation service, transmission service, distribution service, and customer services. In addition, a number of "customer-side" services are currently offered by utilities, at a separate charge, in competition with independent contractors.

Provided below is our vision of how each of these services will be provided as the electric power industry is restructured. In summation, generation service will be open to competition, and the price for that service will no longer be regulated. Rather, consumers will be able to shop for that service, and will pay market prices. Transmission service will be provided on a regulated basis from a regional Independent System Operator; transmission services will be regulated by the FERC. Distribution services will continue to be provided on a monopoly basis by the electric utility, regulated by the BPU. As well customer services, at least initially, will be provided by the electric utility at prices regulated by the BPU.

B. Unbundled Services

1. Generation Service:

The specific industry model for the introduction of retail competition has been hotly debated in this proceeding, as it has in other state proceedings across the country. What is generally agreed among the commentators, and what we conclude, is that the generation (production) function is no longer a natural monopoly, and that power suppliers can and should compete directly against one another. For this to occur, the current vertically-integrated industry structure must be unbundled at a minimum into separate generation, transmission, and distribution functions as will be addressed below.

As the power production and supply segment of the industry is opened up to competition, economic regulation of generation as the Board has historically applied it will be ended. Rather, generating assets will be subject to market forces, with production from those facilities fetching market prices, based upon spot markets or individual negotiations between buyers and sellers as described below[9].

While economic regulation of generation would be eliminated, we emphasize that there is a need to continue environmental regulation, including siting and permitting, of

[9] As will be described in a later section of this report, net revenues produced by existing utility-owned generation sources will be determined for a transitional period of time by a combination of market forces and regulation, as exercised through the establishment of a stranded cost or market transition charge.

generating facilities in the State. Such siting and permitting regulations should be the same and applied equally to all generation facilities in the State in order to ensure a fair competitive market[10].

With respect to creating a level playing field for the siting of power plants, we do not envision this entailing any State-mandated changes to local zoning and land use ordinances. These should continue to be developed and applied at the local level. However, at present, electric utilities, as provided for in N.J.S.A. 40:55D-19, may file with the Board for an override of a siting denial by a municipality per local zoning ordinances, and the Board may so grant, if it is shown that a proposed power plant (or other proposed utility facility such as a transmission line) is "reasonably necessary for the service, convenience and welfare of the public." The intent of the law is essentially to provide the Board with the ability to override decisions made in a particular locale, which do not best serve the larger public benefit. Non-utility generators (NUGs) do not enjoy similar State-sanctioned redress against adverse local decisions. In order to provide for a competitive generation market, there must be equal treatment of all generators with respect to siting. N.J.S.A. 40:55D-19 must either be expanded to include NUGs, or must be amended to eliminate a utility's ability to seek override of local ordinances for purposes of constructing a generating plant.

On the other hand, the Electric Facilities Need Assessment Act (EFNAA) provides that, prior to the construction of a new electric generating plant of 100 MW or more; or the addition to an existing electric generating plant that will increase its capacity by 25% or by more than 100 MW (whichever is smaller), a public utility must apply for and obtain

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[10] There is as well a critical issue with respect to the application of environmental standards to generating plants located in different States, which is addressed in a later section of this Order.

a Certificate of Need (CON) with the BPU. The EFNAA, adopted in the early 1980's in the wake of large and costly nuclear power plant construction programs, provides for a lengthy and detailed review by the Board of the need for a planned power plant prior to construction. This process is estimated to take up to three years to complete. In addition to addressing the need for the additional generating capacity, the EFNAA requires as a condition to issuing a CON that the proposed plant is determined to be the most efficient, economic and environmentally sound option available. NUGs are not covered by the EFNAA, and accordingly are not required to seek nor obtain a CON prior to construction. While in a regulated, monopoly electric utility industry structure the EFNAA provided important public protections against wasteful and unnecessary utility power plant construction projects, in a competitive marketplace, where the project owner and not the ratepayer is taking the risk of a poor investment, such a requirement is unnecessary. Moreover, imposition of CON requirements on one segment of the industry (i.e. utilities) and not another, results in an unlevel playing field. We therefore recommend that, concurrent with the transition to a competitive retail electric marketplace, that the EFNAA be repealed.

For economic regulation of power supply to be ended, the power supply market must be fully competitive. As previously described, this requires the formation of an entity such as an ISO to operate the transmission system in an unbiased manner. Moreover, in order for the electric power market to function in an efficient and fully competitive manner, it is imperative that no individual seller or group of sellers be able to influence the market price for power. Were such market power to exist, a cessation of economic regulation of supply could lead to unintended and unwanted results, as will be described.

Two types of potential market power have been referenced in this proceeding, and in the restructuring debates throughout the country: vertical and horizontal. Vertical market power can occur when a single firm controls successive stages of production in an industry.

In the electric industry, this could occur when a firm or firms actively competing in the generation/supply business control(s) the delivery system, i.e. transmission and distribution. Quite obviously, such an industry structure is fraught with the potential for abuse by the firm(s) controlling access to the delivery network. In short, a transmission-owning utility seeking to sell power to consumers in an unregulated market, could restrict its competitors' access to the wires and thereby "hold out the competition." Without effective competition, such a utility could then charge inflated prices to customers.

As described previously, it is envisioned, and indeed it is a precondition to the introduction of a competitive retail market, that an ISO will be in place to operate the transmission system and take control out of the hands of utilities that also own generating assets. Accordingly, the ISO will have no interest in any market participant. This will ensure that all suppliers have equal and open access to the interstate transmission grid, and that vertical market power as described above cannot be exercised.

As well, utility-owned generating assets and related generation operations should, at a minimum, be functionally separated from the transmission and distribution services of the electric utilities in the State. In this manner, while an entity may still own assets in various stages of the industry, such shared ownership cannot be translated into undue preference or unfair competitive advantages in competitive markets, through hidden subsidies provided through monopoly services. It has been argued by a number of participants in this proceeding that functional separation still requires substantial regulatory oversight to prevent such hidden subsidies from occurring, and that divestiture of generating assets by utilities is required to provide the most certain protection against cross-subsidization between non-competitive transmission and distribution services and competitive generation offered by utilities.

Divestiture of generation assets by the utilities has also been advocated as a means of alleviating horizontal market power concerns[11], by dispersing ownership of generating assets. Currently, the vast majority of the approximately 57,137 MW of generating capacity located within the Mid-Atlantic region is owned by electric utilities. However, that ownership is spread among the eight utility companies comprising the PJM power pool, with the largest ownership share by any one company being about 19.0%. Moreover, substantial blocks of power from generating sources outside the PJM region are being and will be sold into this region. On the other hand, with one merger of PJM utility companies (BG&E and PECo) already pending approval before both state and federal regulators and another proposed merger (ACE and Delmarva) recently filed before the FERC as well as State commissions, concerns regarding market concentration quite naturally increase.

Finally, divestiture has been supported by some as a means of providing a market valuation of utility generating assets for purposes of quantifying potentially stranded generating costs. This will be described more fully in the "Stranded Cost" section of this report.

It has been argued by utility companies, on the other hand, that the offering for sale of large blocks of utility-owned generating capacity in New Jersey as a result of forced divestiture (a so-called "fire sale") could depress market value and thereby exacerbate the stranded cost problem. Moreover, an issue was raised in this proceeding as to the impact which large-scale divestiture of utility-owned generating plants in the State would have on the labor force at those facilities. Finally, substantial question has been raised regarding whether the Board has the authority to order a divestiture of utility assets; raising the

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[11] Horizontal market power can exist when a single firm or firm(s) own or control a high concentration of assets in a given market. For these purposes, this can be taken to mean a high concentration of generating assets in the regional or local power market.

prospect of protracted litigation were such a directive to be issued.

We are committed to assuring that a fully competitive marketplace exists, prior to the cessation of economic regulation of power supply. Accordingly, we reiterate our precondition that a fully independent ISO, consistent with the FERC's ISO principles be in place prior to the introduction of retail competition. Moreover, we reiterate our conclusion that, at a minimum, utility generating assets and functions must be separated and operate at arms length from the transmission, distribution and customer service functions of the electric utilities. Such separation is best achieved, we believe, through the formation of separate affiliated generation companies.

It is undeniable that a divestiture would provide the most definitive means of addressing concerns regarding cross-subsidies and mitigate the need for regulatory oversight of dealings between the competitive and regulated sides of utility operations in order to prevent vertical market power abuse. However, there are numerous legitimate concerns raised with regard to forced divestiture, as described above, and there is real potential for delays which resolution of these issues may cause. The elimination of potential unfair dealings does not provide a sufficient basis in and of itself to take this drastic measure, and we judge such action at this time to be premature. Moreover, the retail market we are proposing, as described below, we believe provides protections for customers against self-dealing between the distribution utility and its affiliated generation and other vertical power abuse. Moreover, within the rate unbundling proceeding to be discussed in a later section of this report, there will be a full opportunity to appropriately allocate all direct and indirect utility generation-related costs, including an assignment of all appropriately allocable shared overheads such as salaries, office space, supplies, etc., to the generation charge, thus preventing hidden subsidies in charges for regulated services.

We would therefore direct that each electric utility restructuring plan provide a plan for, at a minimum, functionally unbundling its generation assets from other parts of its business. Such functional unbundling plan must include sufficient protections to ensure that the generation company is essentially functioning as a separate business unit, with the distribution company treating the affiliate generation company no differently than other competitive suppliers. The burden will be on the utility to demonstrate why such functional unbundling should not entail the formation of a separate affiliated generation company. Moreover, in order to ensure a level competitive playing field we will develop within the context of the restructuring filings codes of conduct for relationships between the distribution company and generation and marketing affiliates, including mechanisms for imposing penalties for any proven violations thereof.

However, we would reserve final judgment on the issue of mandatory divestiture of generating assets until such time as specific and detailed market power analyses have been performed and analyzed. We would direct each electric utility to submit, as part of its restructuring plan filed in response to our final Order in this matter, a comprehensive market power study for Board scrutiny. Such an analysis will have to include not only an assessment of the regional power market, but it must also examine the impact of transmission constraints on the formation of more localized markets, which could lead to undue market concentration in specific geographic locations. Indeed, given New Jersey's geographic position on the eastern end of periodic west-to-east transmission system constraints, and the relative concentration of generating assets in New Jersey under the ownership of relatively few entities[12], this issue will require particular attention. In the event that such analysis demonstrate that there are legitimate market power concerns which may adversely impact the formation of a fully competitive marketplace, and thereby expose consumers to higher prices than would be the case in a competitive marketplace, we would

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[12] We emphasize that this is largely a qualitative observation, and no conclusions should be drawn from this observation without appropriate empirical analysis.

take additional action. As the regional power market and transmission grid are to a large degree common to PSE&G, JCP&L and ACE, upon the receipt of the individual market power studies these will be combined into a generic review process.

Moreover, we would entertain proposals within the restructuring plans filed by each utility for appropriate incentives for the utility to divest itself voluntarily of certain generating assets.

We further emphasize that, even in the event that mandatory divestiture is ultimately deemed necessary to address horizontal market power issues, such an action without appropriate safeguards is not necessarily a foolproof solution to these market power concerns. If a particular non-utility entity or small group of entities were to purchase all generating assets put out for sale, it is possible that market concentration may not be resolved, only transferred. Safeguards would have to be put in place to protect against such occurrences. Moreover, given our concern that electric industry restructuring impact positively on the retention and creation of jobs in the State's economy, the potential impact on the utility labor force of a divestiture would have to be addressed.

We would also note that we would expect that other agencies, including FERC, the Federal Trade Commission and the Department of Justice, will be assessing the potential for anti-competitive activities in power markets throughout the country as the industry transitions to full competition.

2. Transmission Service:

As described earlier, electric transmission is defined generally as the movement of power from the point(s) of generation to the distribution system. Very generally, transmission facilities encompass high voltage (such as 500 and 230 kilovolt) wires mounted on large steel towers and ancillary facilities. Transmission service, because it generally moves electrons in interstate commerce, is thereby subject to federal jurisdiction, as exercised by the FERC. Electric utilities currently jointly own and operate the transmission grid as part of bundled electric service. The FERC currently sets transmission rates based upon cost. The cost of PJM-region transmission facilities jointly owned by electric utilities in New Jersey is currently reflected in "bundled" retail utility rates.

Transmission service also entails the maintenance of the reliability of the system. In general terms reliability means that there is at all times sufficient generation on line to serve customer loads. In somewhat more technical terms, assurance of reliability means the taking of all actions necessary to assure that the amount of power being pumped into the grid, and the amount of power taken out of the grid to serve customers are in exact balance at all instants in time. Moreover, the proper voltage must be maintained on all parts of the power network, to avoid voltage instability which could lead to failure of the grid. Accordingly transmission service, in addition to simply involving operation and management of the transmission wires, also entails some elements of generating facility management and control. These types of generation-related functions, performed as part of transmission service, include load following, frequency control and voltage regulation, commonly referred to as ancillary services.

In a restructured industry, transmission service will be functionally unbundled from the generation and distribution businesses of the electric utilities, and is envisioned to be provided on an open access basis, pursuant to FERC Order 888, by an Independent System Operator (ISO). The ISO is expected to evolve from the current PJM power pool, a regional power grid that covers most of the Mid-Atlantic region including nearly all of New Jersey, central and eastern Pennsylvania, all of Delaware, Maryland and the District of Columbia, and northern Virginia. Transmission service will continue to be a monopoly service, provided by the ISO. Accordingly, the rates charged by the ISO will be regulated by the FERC, on a cost basis[13].

Distribution utilities will be charged for use of the transmission system by the ISO, in a comparable fashion to other transmission system users. Transmission system users, including the distribution utilities, will be charged by the ISO for other services provided related to maintaining power grid reliability, such as ancillary services. It is expected that the "unbundled" transmission rates charged by the ISO to electric utilities will be equivalent to those transmission costs currently embedded in bundled utility rates. Indeed, with greater use of the transmission grid the expected result of open transmission access Order 888, increased revenues are hoped to somewhat reduce overall transmission rates.

3. Distribution Service:

Distribution service is defined for these purposes generally as delivery of electrons from the transmission system to the meter. Facilities employed by the utilities to provide distribution service include switching stations where large transformers step-down the electricity from high voltage taken off the transmission system to lower voltage; poles and lower voltage (such as 34.5 kilovolt) wires along major roads and rights-of-way; substations where voltage is further reduced; poles, wires and transformers along local streets; and the service drop wires coming off the street and into the home at 220 volts. This service is currently provided by electric utilities as part of a bundled electric service distribution company.

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[13] We note that certain elements of transmission service, such as ancillary services, which are provided from generation facilities, may be procured by the ISO through a market solicitation. Accordingly, the pricing for such services may be market-based; however, they would in turn be charged for by the ISO to transmission users at this market-based cost.

In a restructured industry, distribution service will remain a natural monopoly, as we continue to conclude that construction of duplicative electric distribution systems would be inefficient and not in the public interest. As a result, distribution service will continue to be a regulated, monopoly service, provided by the existing electric utilities. The Board will have regulatory authority over the pricing for and the service quality of distribution service. The costs to provide distribution service are generally described as the construction and maintenance cost, and a pro rata share of utility overheads associated with substations, transformers, poles and wires, down to the service entrance on a customer premises. The franchised electric utility will continue to have an obligation to connect customers to the distribution system, and to provide distribution services to all customers. Moreover, the Board will continue to have regulatory oversight to ensure that the utility provides safe, adequate and proper distribution service, and otherwise maintains the reliability of the distribution system.

With respect to the price regulation of distribution services, we note that in preparation for the transition of the utility industry, in July 1995 P.L. 1995, c.180 was signed into law. The Act provides electric utilities with the ability to request alternative plans for regulation, including incentive-based regulation, as opposed to rate base/rate of return regulation, subject to strict consumer standards. We note that once the unbundling of distribution service from the other components of the business is accomplished in October 1998, we would invite proposals for alternative plans of regulation (APRs) for distribution services, which produce incentives for cost efficiency and related benefits for consumers that may not otherwise result from traditional rate base/rate of return regulation of these services. Within such proposals we would explore mechanisms which would incent the distribution utilities to explore and implement all available measures to minimize the cost of the distribution system subject, of course, to service quality criteria. To that end, the distribution companies should begin to gather distribution cost data to assist in such least cost planning studies. As well, we will explore within future APRs whether unbundled distribution service has a different risk profile, and therefore warrants a different allowed rate of return than traditional bundled service.

In a restructured industry where the distribution company is no longer responsible for providing "bundled" electric service, but rather is simply delivering electric energy and capacity produced by third party suppliers to customers, the role of local load balancing is called into question. That is, currently it is the utility's obligation as part of the provision of safe, adequate and proper service to ensure that customer power demands and the input of power into the transmission and distribution system are at all times in balance. This function is now implicitly included in utility bundled service. The specific question is, where individual suppliers will take on the contractual responsibility to provide power to their retail customers only, who will provide balancing services to ensure that aggregate power input into the system matches aggregate customer loads.

As described earlier, the ISO will have the overall responsibility, for purposes of maintaining the reliability of the regional transmission grid, to ensure that the network is in balance. It is our conclusion, however, on a more localized level that at this time the distribution company, as the operator of the distribution system is in the best position to monitor customer usage by all consumers on its system and all power deliveries to serve customers on its system. Accordingly, at least during a transitional period, the distribution utility should be responsible for performing the accounting and administrative function associated with determining where imbalances for individual suppliers and customers occur, and for assessing appropriate charges to cover any load balancing costs incurred. We emphasize that such charges would be based upon the cost directly incurred by the distribution company in providing administrative services related to system balancing and, where necessary, the cost of procuring any resources to address imbalances, either directly or via the ISO, in the competitive marketplace. It is further noted however that, to the extent suppliers make payment for imbalances directly to the ISO, suppliers must not be "double charged" for these services by the distribution company.

4. Customer Services:

Customer services consist of metering, billing and other administrative activities associated with maintaining a customer account. These services are currently provided as part of bundled electric utility service, and the costs are currently recovered in the monthly service charge. These charges represent a relatively small component of a customer's monthly bill, ranging from about $2 to $4 per month for residential customers in the State. While the distribution company in its current role as a bundled service provider is essentially a monopoly provider of customer services, these do not appear to us to be natural monopoly services. In other words, there is no technological or organizational reason why in the long term the distribution utility is the only entity that could install a meter at a residence or business, compute and assess bills, provide account administration and support and provide other information services. As technologies develop, all of these services are potentially competitive. Indeed, as the industry evolves we foresee energy service companies offering new and innovative customer services in a competitive market as part of a larger package of services including power supply. We foresee such offerings as resulting in reduced costs and expanded choice for consumers.

However, at present the development of new and innovative metering, billing and other customer services is at a formative stage, and there are numerous logistical issues yet unresolved concerning opening these services up to competition, including the protocols and infrastructure necessary for the exchange of data between energy service companies and distribution companies. Moreover, an immediate competitive market for customer services is not a prerequisite to introducing retail power supply competition into the industry. Too, as described above these services do not currently represent a large component of customer bills, and therefore this is not an area that promises immediate and substantial savings due to competition. Moreover, yet unaddressed is the issue of how, if these services were immediately opened to competition, the existing infrastructure of utility meters, billing equipment and support personnel, would be impacted, and what the cost implications of these potential "stranded costs" would be. Accordingly, it is our conclusion at this time that at least initially the distribution utilities should continue to offer customer services on a regulated basis. We would, however, entertain proposals in a utility' s restructuring plan filings for allowing metering and/or billing to be provided by third parties on a voluntary basis if such plan can be shown to provide benefits to consumers. Moreover, we direct that the utilities address in their restructuring filings what actions must be taken and are being taken to prepare for competition in the customer service market and, further, to demonstrate that actions being taken or recommended will not inhibit a timely transition to competition in this area.

We will form a Customer Services Working Group, comprised of a representative cross-section of stakeholders, to further review these issues and to develop a report with recommendations on the introduction of competition into the customer services area. We will target a report to be submitted to the BPU, with recommendations, by July, 1998, after which we will solicit public comment and render further determinations in this regard.

There are some immediate issues with respect to metering in a restructured industry. Specifically, an issue that has been debated in the context of the implementation of the State's natural gas unbundling programs over the past two years, and which has been discussed in this proceeding, is the need for real-time automatic meters[14]. Real time meters

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[14] Except for certain very large customers which have magnetic tape meters which record actual customer usage levels on a continuous basis, currently electric meters only record aggregate usage. Assuming a meter is only read monthly, the only information available is the aggregate power consumption during the month; daily usage patterns are unavailable.

provide a continuous recording of customer electric consumption. It has been argued that real-time meters are necessary in a competitive industry structure for two primary reasons. First, only with real-time meters will customers be able to respond to changing power market prices during different periods of the day, week or month. With a real-time meter, customer usage can be assigned to specific time periods, for instance hours, and matched with changing power prices through the course of the day. Accordingly, the customer would have the opportunity to be rewarded and reduce his/her overall bill by consciously shifting discretional power usage to low cost periods. Second, without real-time customer usage information, it will not be possible to accurately assign the costs of load balancing to those causing imbalances to occur, since there would be no way of accurately knowing when during the day a customer's usage occurred.

We have seen in the gas industry, however, that the cost of a real-time meter can be prohibitive, particularly for smaller customers, essentially serving as a barrier to competition by offsetting any potential savings offered through a switch of suppliers. It has been argued by marketers in this proceeding that load profiles can be used in lieu of real-time meters to estimate the loads of individual small customers and thereby appropriately assign charges for imbalances between a third party supplier's power deliveries and its customers' actual consumption. Indeed, load profiles have been employed for this purpose in the retail competition pilot program in New Hampshire.

From a theoretical standpoint, we favor the use of real-time meters as the most accurate way to gauge customer usage, prevent gaming and assign the costs of imbalances, as well as to elicit consumer response to market prices. From a practical standpoint, however, for many customers the imposition of a requirement for a real-time meter may effectively take away the potential savings from retail competition. On the other hand, comments were received that real-time meters and attendant opportunities for load shifting are essential to providing a chance for meaningful savings for small customers; that is, commodity cost savings alone for low-usage customers will not be enough to stimulate the market. It is our conclusion that for residential and small commercial customers there be no immediate requirement for the use of a real-time meter. We would entertain specific proposals in each utility's restructuring plan for an appropriate definition of a small customer for these purposes, as well as for proposals to phase in the use of real time meters for all customers at a later date. In this regard, however, as noted previously, any such proposals by the utility to install real-time meters must address what impact such program would have on the transition to a competitive customer services marketplace. We further and specifically note that such initiatives must not create additional stranded costs when customer service are opened to competition at a later date.

Another concern of immediate import which has been raised with respect to customer services, especially where the utility maintains the responsibility for metering, is the need for the expeditious transfer of usage data by the distribution company to third party suppliers, in order for all applicable charges to be determined and for timely completion of bills. The development of a system to ensure timely customer usage data transfer and billing is critical to a well-functioning retail power market. This is an issue that must be addressed by the distribution companies in their restructuring plans. Moreover, we would encourage the distribution companies, in cooperation with third party suppliers, to explore the development of a single electronic system and data format in order to minimize cost and maximize efficiency in this regard. It is recognized that the long term role of the distribution companies in this function should be finalized, in order to allow for the necessary investments in data system infrastructures.

5. Customer-Side Energy Services:

A wide array of energy services are currently offered on the customer side of the meter by independent third parties, including electricians, plumbing, heating and cooling contractors, energy service companies, as well as in some cases electric and gas utilities. These services include appliance and equipment maintenance and repairs and appliance service contracts. It is generally agreed that a competitive market already exists for these services. However, some parties, particularly independent contractors, have argued that utilities participating in offering these services have an unfair competitive advantage or otherwise utilize their traditional utility role to subsidize their activities in these areas. As a result, within this restructuring proceeding it has been argued that utilities should divest of all customer-side energy services.

The Board has concluded in numerous proceedings that it does not have the legal authority to prohibit utilities from participating in customer-side services. Indeed, it has found a nexus with other utility services and otherwise found it in the public interest for utilities to offer these services. However, contrary to the assertions of certain utilities, the Board has found that, to the extent these services are offered by a utility as opposed to a separate subsidiary, it does have general regulatory oversight over the offering of these services, and specific Board approval must be sought and obtained by the utility prior to offering such services. We emphasize that the scope of review is generally limited to ensuring that the price being charged for such services is not unduly discriminatory and does not result in a subsidization by the general utility ratepayer base, and that the offering of such services does not adversely impact the utility's ability to provide safe, adequate and proper service. To demonstrate that no cross-subsidization exists, the utility must show, at a minimum, that the prices being charged meet or exceed the fully allocated cost of providing the service. However, subject to meeting this standard, pricing of competitive customer-side services is not strictly regulated to the extent that monopoly distribution services are regulated.

Within the context of this industry restructuring proceeding, we conclude that there has been no compelling reason given why utilities should be precluded from offering customer-side services in a competitive marketplace. Various customer-side services, such as space heating and water heating equipment repair and service contracts, have been offered by the utilities for many years. It is our view that customers are generally pleased to have the option of receiving these services from their utility, and thousands of customers have availed themselves of these services. We conclude that there is no good reason for us to forcibly take this option away from customers.

Indeed, we see such services as providing an opportunity for utilities to utilize existing assets, as has been argued by numerous parties, to create sources of revenues that can be used to mitigate stranded utility costs resulting from introducing competition in the power supply market. In other words, during the transition period when customers will be asked to help offset some of the financial losses that utilities would otherwise suffer as a result of submitting uneconomic generating assets to competitive forces, it is only fair and appropriate that gains realized from utilizing utility assets in other competitive services be used to help defray those stranded generating costs.

We do concur with the recommendations made on behalf of the independent contractors, independent power producers and other entities that the offering of such competitive services by utilities must be subject to strict standards for fair competition. Moreover, it is our view that any such competitive functions provided by the utility must be charged at fully unbundled rates, reviewed by the Board, and must be shown not to result in any cross-subsidization by the general ratepayer base of the distribution utility. In addition, the utility must maintain books and records, and provide accounting entries to the Board, such that there is a strict separation and allocation of the utility's revenues, costs, assets, risks and functions, insofar as possible, between these competitive and its non-competitive functions. This would include separate accounting for time by utility employees between utility service functions and competitive service activities. As well, the Board will institute a periodic audit requirement concerning these services.

In this manner, independent, non-utility purveyors of competitive services will have the opportunity to fairly compete in these markets with the utilities.

We will develop specific standards for fair competition, both with respect to the performance of competitive services by electric utilities as well as regarding the interrelationships between the electric utility and its affiliates participating in competitive energy services, within the context of the restructuring filings to be made by the utilities later this year. To that end, within each of their restructuring filings we will require each utility to submit proposed standards for fair competition related to competitive services, as well as affiliate relationship standards. These issues and proposals will be combined and adjudicated via a generic "mini-proceeding' to be spun-off from the main restructuring proceedings.

C. The Industry Model For Retail Competition

Three principal industry models for the introduction of retail competition have been proposed and debated, not only in this proceeding but in other jurisdictions as well: the poolco model, bilateral contracts model and a hybrid of the two. All of these models rely upon an ISO to provide transmission service on a fair and equal basis and manage the flow of electrons over the transmission system and to ensure overall system reliability; however, the nature and degree of control of market participants varies significantly among the models, with poolco generally imparting the greatest degree of control over market participants and the bilateral model generally the least.

In the poolco model, there is a central power pool (Pool), commonly referred to as the "power exchange" or "energy market", for which membership is mandatory for all generators. As was proposed in the PJM Supporting companies' wholesale restructuring filing, this Pool is operated by the ISO. The Pool operates by conducting a day ahead auction in which it solicits bids for energy from generators in half hour or hourly increments. The Pool operator stacks the bids from lowest to highest price until a sufficient amount of generation is identified to serve the projected load in each time period. The highest bid from the selected stack in each time period will be the market clearing price for that time period. The Pool operator has control over generator dispatch according to the submitted bids. Each generator whose bid has been selected by the Pool in that period receives the market clearing price, in addition all buyers who receive power from the Pool pay that market clearing price (the price paid by buyers may be marked up to cover transmission constraint costs and ancillary services provided by the ISO).

In the poolco retail model, all buyers are required to purchase power directly from the Pool. Moreover, it is proposed that the existing utility companies (in the restructured industry, the distribution company) purchase power from the Pool, and resell it to customers at the Pool market clearing price. In essence then, the Pool represents a competitive wholesale market and the retail customer remains captive to the local utility for the supply of power (albeit at a competitive market price rather than a regulated, cost-based rate as is currently the case). However, the poolco model would allow retail customers to enter into other purchasing arrangements called contracts-for-differences (CFDs) with suppliers or other third party market participants. CFDs are financial instruments that provide retail customers the ability to hedge the fluctuations in Pool prices and otherwise establish a known price around power physically delivered through the Pool.

Proponents of the poolco model argue that there is nothing that can be done with retail bilateral contracts as proposed in a "direct access" model (described in more detail below), that cannot be done through the poolco and CFDs. For this reason the poolco model is also referred to as "virtual direct access." The advantages of poolco, according to proponents, include the establishment of a visible, robust spot energy market with transparent pricing, the assurance of universal service, and a shorter implementation time and lower transaction costs. As well, it is argued that poolco, through more centralized control, maintains better overall control of the power grid and, through central dispatch, maximizes economic efficiency. Importantly, it is argued that purchase of power by the utility at one market clearing price will assure that all customers will benefit from the competitive market. Finally, it is argued that a continued reliance on the utility to supply power to retail customers avoids jurisdictional disputes between the FERC and the Board.

In the bilateral contract model also referred to as "direct access" or "customer choice," retail customers negotiate directly with sellers in the marketplace for terms of delivery and price of electric energy and capacity. The role of the ISO is much more limited than with poolco: it receives from the suppliers information related to the transactions, including the location and dispatch schedule of generators, and the delivery point(s) (the price of the transaction is not considered relevant to the ISO). With information for all the transactions, it will then verify that sufficient capacity is scheduled to serve regional load, and that sufficient transmission capacity exists to complete the transactions and to otherwise maintain system reliability. The ISO would have the ability to procure capacity and energy on a short term basis to maintain system balance and relieve transmission constraints. These resources would be procured in a competitive manner and the costs would be passed on to transmission system users.

Proponents of direct access argue that this is the only model truly premised on market forces, with buyers and sellers bargaining directly with one another and individually determining the value of services. As well, it is argued that customer choice provides for greater product differentiation, pricing options and development of new customer services which can be packaged with power purchase arrangements. Too, the bilateral contract market is believed to foster the development of spot, futures and forward markets. The spot and futures markets, which have developed in the natural gas market, are publicly reported and thereby provide market price transparency. As well, it is argued that a robust forward market will signal market needs, thereby improving capital allocation and providing the appropriate mechanism to attract capital investment in new capacity when needed.

Proponents of direct access argue that the poolco approach leaves the supply function within the hands of a monopoly supplier, as all customers would be forced to continue to purchase power from the local utility company, albeit presumably at a spot market price as opposed to at prices based upon the cost of utility generation as is currently the case. As such, direct access proponents argue that the poolco approach prohibits true customer choice of their energy supplier.

The hybrid model, which consists of bilateral contracts as well as a voluntary Pool, combines many of the features of poolco and direct access as previously described. Retail customers would have the ability to negotiate a power supply agreement directly with a supplier of their choice, or may simply choose to accept Pool-supplied power at the market clearing price (or as hedged via a CFD). In the hybrid model, participation in the power exchange is voluntary for both generators and customers (or their aggregators).

It is our conclusion, having considered the arguments presented, that the hybrid model for retail competition providing for both bilateral contracts and a voluntary power exchange, will best serve the interests of the State. The hybrid model combines the attributes of both the poolco and the straight bilateral contract approach and, conversely, mitigates the alleged shortcomings of both. By permitting customers the freedom to negotiate power purchase arrangements directly with suppliers, there will truly be customer choice, providing the impetus for the creation of a wide range of services and pricing options to best meet individual customer needs. This condition, we believe, is fundamental to any competitive marketplace.

However, we are mindful of the criticism that a strict bilateral contract approach does not give rise to price transparency, as each deal is negotiated privately, and the related concern that small customers without pricing information or sophistication will not receive the same benefits through the negotiation process as larger customers. While aggregation provides the opportunity for small customers to garner additional bargaining leverage and to lower transaction costs that may otherwise not be available for such customers individually to benefit from a strict bilateral contract marketplace, we do not wish to rely solely upon such mechanisms to protect the interests of the small customer. Accordingly, the formation of a bid-based power exchange is essential, we believe, both as a means to provide market information as well as to provide a competitive supply marketplace from which customers may purchase power. We anticipate that such a power exchange will emerge as a result of the restructuring of the PJM power pool. In this manner, the power exchange will serve both as a source of pricing information as well as an alternative source of supply for those customers unable to procure power at acceptable terms and prices via a bilateral contract negotiation. As with the poolco model, customers opting to purchase power directly from the Pool could either accept the short term Pool price or enter into a financial hedging arrangement such as a CFD. Through this industry model, we believe, all customers, large and small, can obtain the benefits of the competitive marketplace.

In order to maintain system reliability, all bilateral contracts would have to be nominated to and scheduled through the ISO, which would process all information concerning points of supply and points of delivery, and confirm that the transmission grid could accommodate all proposed transactions. There has been substantial discussion concerning whether the power exchange should be operated by the ISO, or whether it ought to be operated by a separate entity that merely coordinates with the ISO. Certain commentators, particularly marketers and independent power producers, strongly advocate that reliability functions, as performed by the ISO, and power exchange market functions be performed by separate entities. Specific reference has been made to the California PUC decision to separate the ISO and the power exchange into separate entities, wherein separation of these functions was directed in order to eliminate any perception that the ISO could gain financially by preferring one supplier over another in dispatching generation and scheduling capacity. Conversely, certain utilities have argued that it is essential for the ISO to establish a buy/sell market price in order to manage the grid in a timely manner in the event of unexpected increases in load, large unplanned plant outages or developing transmission constraints. Moreover, while another body could perform the functions leading up to the declaration of a market price and transmit the results to the ISO, it is argued that this adds an unnecessary level of complexity and inefficiency.

We are not convinced that the power exchange and grid management and reliability functions need to be separated. Indeed, we see the separation of these functions as giving rise to inefficiencies and added costs and complexities. We note in this regard that in California a tight power pool has not previously existed, both the ISO and the power exchange are being created as part of the restructuring in that State largely from scratch. Conversely, in the Mid-Atlantic region which includes New Jersey, the PJM power pool, a tight pool that has historically performed grid operation, reliability and economic dispatch functions, has an extensive infrastructure in place. The Board has previously taken the position in filings before the FERC that this extensive and well-developed infrastructure has served the region well for decades and ought not be dismantled; rather it ought to be built upon, modified and restructured in order to preserve existing benefits while accommodating the new, competitive environment. We are quite mindful of the concern of some that putting the administration of the power exchange in the hands of the ISO could put the ISO in a position of favoring one generator over another. However, what this gets back to ultimately is the issue of whether the ISO is truly independent; a concern that we believe transcends the issue of whether or not the ISO is involved in the energy market. The Board, as we believe do all of the parties in this proceeding, deems as critical the independence of the ISO from all market participants. Moreover the FERC, which will have the ultimate jurisdiction over a regional ISO, has made its intentions clear in this regard, not only in the ISO guidelines included in Order 888, but in its recent Order rejecting both PJM restructuring filings before it. We are confident that the ultimately approved Mid-Atlantic ISO will be structured in such a way as to be truly independent from all market participants. As such, concerns regarding manipulation of the power exchange by the ISO, when weighed against the potential downsides to separation of the power exchange from the ISO, are unpersuasive.

D. The Schedule for Phase-In of Retail Customer Choice

As has been described, critical to the functioning of a fully competitive, retail power market that retains the current high degree of system reliability, is the establishment of an ISO, or its functional equivalent. As also indicated, it is expected that a regional ISO transformed from the PJM power pool to implement a fully competitive wholesale market will be approved for implementation some time in 1997. While we had previously anticipated that the restructuring of the PJM would be complete and the regional ISO up and running by mid-year 1997, at this point the precise timing is uncertain. There remain unresolved issues in the collaborative discussions taking place, a compliance filing for a permanent restructuring of the PJM Power Pool is due to be filed with the FERC on May 31, 1997, and the timing of the FERC's subsequent review and approval process is uncertain. It remains our judgment at this time that there should be a reasonable transition period for the ISO to fully implement its open access responsibilities at the wholesale level before adding the additional complexities associated with the introduction of competitive retail transactions. As well, there are a number of critical proceedings to be conducted and completed, and technical and logistical issues as identified herein to be resolved, prior to the introduction of full scale retail power competition for the millions of customers in the State. However, given the substantial potential benefits for the State's residents and economy associated with electric power competition, there should be no unnecessary or unreasonable delay in moving forward.

Accordingly, we conclude that the following timetable for the implementation of a phase-in of retail competition in each electric utility's service territory over an approximate twenty-one month period is appropriate:

<u>Date</u>	<u>% Eligible Customer Load</u>
Oct. 1, 1998	10%
Jan. 1, 1999	20%
Apr. 1, 1999	35%
Oct. 1, 1999	50%
Apr. 1, 2000	75%
Jul. 1, 2000	100%

We urge that the FERC review process be completed, and that the restructured PJM ISO be up and running for the wholesale power market by no later than October 1997, to allow for a minimum one year shakeout period prior to the October 1998 date for the commencement of retail competition in New Jersey.

There has been significant discussion as to the appropriate definition of eligible load with respect to a phase-in schedule. Specifically, two different approaches have been debated. The identified percentage of eligible load can be regarded as a target for the percentage of customer load converting to a third party supplier, with the entire customer base actually eligible to seek alternative suppliers from day one on a first-come, first-served basis. To the extent targets are exceeded, there would be a process whereby the utility could request, or the Board could determine, whether requests beyond the targets could be accommodated. Alternatively, each step of the phase-in can represent a discreet block of customers eligible to convert, with each block established by such means as specific designation, random assignment, lottery, or an open season. Each approach has identified shortcomings.

A separate issue concerning the phase-in of retail customer choice is the extent to which different classes of customers are provided choice. Specifically, there have been proposals made in a number of the States that a phase-in begin with providing retail choice to the largest (industrial and commercial) customers first, and gradually opening choice up to the smaller commercial and residential customers. Other proposals have been made that would mandate simultaneous choice for all customer classes.

It is our firm belief that retail choice must be phased-in and provided to all groups of customers simultaneously. To provide only one group the ability to negotiate power supply arrangements with third party suppliers, for instance large industrials, while other groups such as small commercial and residential customers remain obligated to purchase power from the utility, would be fundamentally unfair and possibly discriminatory. Moreover, such an arrangement would be violative, we believe, of one of the fundamental goals of restructuring, that is to provide electric rate relief to all consumers in the State.

We therefore conclude that each step of the phase-in of customer choice must encompass a cross-section of customers that is representative of the overall customer mix in each utility's service territory.

Accordingly, during each phase the designated percentage of eligible load must apply to each customer class. Eligibility for retail access will be on a first-come, first served basis up to the designated percentage of total load for each customer class.

Of course, there may well be a tendency for certain suppliers to focus their marketing efforts on the most lucrative customers, which may well include industrial and large commercial customers, and perhaps a subset of larger, more affluent residential customers. As a result, while all market segments are simultaneously and proportionately provided the opportunity to shop, there is a concern that in actuality certain customer groups will have few options available. Such an outcome is inconsistent with our intent that all customers benefit simultaneously. Nonetheless, we indicated our belief in the Draft Report that a specific mandated customer portfolio for each supplier would be overly prescriptive.

Substantial comment was received in response to the phase-in proposal set forth in the Draft Report. A primary concern was that, with a gradual and protracted phase-in schedule, there would be unfair results as certain customers would be able to switch suppliers and reduce energy costs long before other customers. This was argued to be particularly problematic when the "have" customer happens to be a direct competitor of the "have not" customer. In addition, concerns were raised that a requirement delaying the implementation of the next step of the phase-in until all customer blocks of the previous phase-in were filled, could unfairly inhibit those customer classes with a greater desire to exercise their choice.

In order to mitigate the potential adverse impacts of the phase-in, as described, the schedule for completion of the phase-in, as set forth above, has been accelerated by nine months from the proposal in the Draft Report. Under the modified schedule, 35% of total load for each customer class will be eligible to choose within 6 months for the introduction of retail competition, 50% will be eligible within one year, and 100% of all customers will be eligible to switch suppliers within twenty-one months.

We further conclude that the degree of one customer class' propensity to exercise its choice to switch suppliers should not inhibit another customer class' ability to switch.

Accordingly, we will not require that each block of the phase-in be filled for each customer class prior to opening up the next block to competition. We emphasize, however, our continued concern that certain customer classes not be ignored by third-party suppliers in their marketing efforts and thereby be effectively denied the ability to switch if they so desire.

We do believe that the availability of market-priced Basic Generation Service for all customers, in combination with the imposition of non-bypassable transition charges on all customers regardless of their supplier and the provision of near term rate reduction for all customers, as will be discussed later, will mitigate against the otherwise potential unfair results associated with our adopted phase-in mechanism. However, in addition we will closely monitor the results of each step of the phase-in to identify if any significant, inappropriate disparities emerge in the results for different customer classes, in which case we would take the necessary and appropriate actions to remedy the situation.

Moreover, to provide a greater opportunity for a cross-sectional mix of customers to benefit from retail choice, including residential and small commercial users and governmental entities, we will increase each block of the phase-in by up to an additional 5% of customer load to accommodate municipal aggregation transactions, as will be described in the next section of this report, and state and county government entities.

Finally, we have a particular concern that the logistics be in place by which the electric utilities are able to process and implement in an orderly fashion, beginning October 1, 1998, requests to change suppliers. In order to allow the utilities to process and efficiently deal with the demand to change suppliers we are directing the utilities to provide in their restructuring filing proposals for an appropriate registration period, where customers would be required to notify the utility in advance of their choice of alternative suppliers.

While the Board will require each of the utilities to propose a specific phase-in mechanism in their restructuring filings we will form a working group to review and address on a generic basis the specific mechanics for implementing the phase-in including any unresolved technical and logistical issues relating to the phase-in of retail competition, such as but not limited to, the complexity of tracking retail transactions, metering and billing.

E. Customer Aggregation and the Role of Municipal Entities

While it is our finding that a voluntary power exchange be established to provide a low transaction cost, price transparent alternative for customers, we nonetheless do conclude that customer aggregation should be permitted and indeed encouraged. This would, we believe, allow customers through their aggregators to garner bargaining leverage with suppliers, to make available through aggregators a degree of market expertise not otherwise available, and to significantly reduce transaction costs typically associated with smaller customers. We would permit a wide range of aggregation scenarios, including not only for multiple and diverse sites owned by a particular entity, but as well aggregation by geographic location. We envision and propose to permit geographically-oriented aggregation, including aggregation by political subdivision.

In permitting aggregation by political subdivision, we expressly note however that such aggregators would not constitute the formation of a municipal utility, but rather would only negotiate for and purchase supply on behalf of retail electric customers within the jurisdiction. Moreover, we emphasize that any arrangements between an aggregator and representatives of a political subdivision should be subject to appropriate authorization by governing bodies, local elected officials and/or constituents within the jurisdiction. Further, we envision that individual retail customers within such a political subdivision would not be bound to accept power from the municipal aggregator, but could procure power from an alternative supplier of their choosing.

The issue has arisen in this proceeding, as to the applicability of the herein policies as proposed by the Board regarding Statewide retail electric competition to the existing municipal electric and cooperative utilities in the State.[15] The municipal and cooperative electric systems in New Jersey, except in the case of the City of Vineland which owns its own generation, purchase power in the wholesale market for distribution and resale to constituent retail customers. These entities have been in existence for decades. Sales of electricity to end users within municipal boundaries by a municipal utility system are not subject to State regulatory authority; rather, they are subject to local review. Local voters have the ultimate authority over the performance of these systems. Accordingly, it is the view of this Board that the proposed statewide electric restructuring plan herein should not be imposed upon the existing municipal and cooperative electric systems. However, this is not to say that retail customers within those affected municipalities should be precluded from the option of choosing their own power supplier. Rather, it is our recommendation that customers within those jurisdictions should have the option to choose, through an appropriate political process as determined by the Legislature and/or the local governing bodies, to retain the current structure or to open retail power supply up to competition under the State's policies enunciated herein. We emphasize in this regard that we are not necessarily advocating the creation of a new political or bureaucratic process to evoke a determination as to whether a municipality introduces retail competition. To the extent that the Legislature and/or local governing bodies conclude that existing processes are

[15] There are ten such entities in the State, including the Borough of Butler, City of Lavalette, Madison Borough, Borough of Milltown, Borough of Park Ridge, Borough of Pemberton, City of Seaside Heights, Borough of South River, City of Vineland, and the Sussex Rural Electric Coop Inc., serving approximately 2% of the retail electric load in New Jersey.

sufficient, we would not suggest any further action in this regard.

We conclude, however, that should an existing municipal or cooperative utility choose through such political process to remain an exclusive provider of retail power within its jurisdictional boundaries, and thereby effectively preclude such retail market from competition, such entity should not be permitted to offer retail power for sale to customers outside of the territorial limits of the municipality. Not only is such a policy appropriate for reasons of fairness and reciprocity, but as well any such extra-jurisdictional sales would render such entity subject to State regulatory authority, in which case the herein policies would apply.

It is important to emphasize the distinction between existing municipal utilities and newly formed municipal utilities through a "municipalization" process. Moreover it is important to distinguish between a municipal aggregator and the formation of a new municipal utility via municipalization. First, with respect to the formation of a new municipal utility, while such municipalization is not prohibited under current law, the Board has taken the position that such process would be subject to our review in order to, among other things, ascertain the impact on remaining public utility customers. Of specific import in this regard, is the applicability of stranded cost charges on the departing customers. It is our belief that this Board has the jurisdiction to impose appropriate fees on departing retail customers of the public utility in the event of municipalization, no different than in the event of a retail customer switching suppliers under a transition to retail competition.[16] To do otherwise would impose higher costs and rates on the

[16] The Board has filed at the FERC a Motion for Rehearing dated May 23, 1996, contesting the Commission's ruling in Order 888 that it has jurisdiction over the establishment of stranded cost charges in the event of a municipalization. Of note, in any event, is the FERC ruling that the stranded costs of the public utility resulting from a municipalization are recoverable from those departing customers.

remaining customers of the public utility; a result clearly not in the public interest.

Finally, while we do have regulatory jurisdiction over the Borough of Butler municipal electric utility, as it makes retail sales to customers in a number of neighboring towns, we will not require Butler Electric to submit restructuring plans, or stranded cost and unbundling filings at this time. By virtue of the introduction of wholesale competition brought about by the federal Energy Policy Act of 1992, Butler Electric has already provided substantial rate reductions to customers over the past several years by exercising the ability to switch wholesale suppliers (we note that since such switch of suppliers occurred prior to FERC Order 888, stranded costs charges were not assessed). Indeed, presently residential ratepayers in Butler's territory currently incur average monthly bills some 33% below the State average. Accordingly, we conclude that there is no need at this time to submit the municipal utility, with limited resources, to the comprehensive requirements of these three filings.

F. Reliability

Under the current electric power industry structure, the State and indeed the nation enjoys a high degree of service reliability. That is, other than the occasional localized power outage due to weather or accident-related downing of wires, or failure of distribution equipment, consumers and businesses have come to expect, and indeed receive, electric power instantaneously on demand with little or no interruption. Most home heating and cooling systems depend, either directly or indirectly, on electrical power. Business and industry require reliable electric power on a continuous basis to run their engines, machines, computers and other essential business equipment. Electronic equipment of various types, including personal computers, VCRs, audio equipment and the like, have become commonplace in many homes. Moreover, life support equipment, both in health care facilities and in the home, depend on electric power. Accordingly, reliable electricity can certainly be considered an essential service which is vital to the health and well-being of the State's residents, and to the vitality of our economy.

It is a common goal of all parties to this proceeding that the reliability of the electric power grid should not be compromised to any degree as a result of industry restructuring. We concur that this is an absolute requirement, and that service reliability must remain our top priority as we implement the move to a restructured industry.

Reliability can generally be broken down into three main categories: First, is the assurance that there are and will be adequate supplies of generating capacity to meet customer demands at all times. This includes a reserve margin to cover such contingencies as abnormal weather and planned and unplanned power plant outages.

The second area relates to the high voltage transmission system, which moves electrons in bulk from remote points of generation to local distribution systems. The transmission system is operated within certain physical and operational limitations in order to maintain reliability. These include thermal limitations that dictate how much current can move over the wires before equipment begins to overheat, voltage stability limitations that mandate that voltage be maintained within very tight constraints to prevent voltage instability and possible system collapse, and power stability limits. These constraints dictate how much power can be moved across the system, from generators to local distribution networks, at any point in time. Indeed, during times of heavy electrical demand, or as a result of occasional unusual events such as the loss of a transmission line or a key generator(s) in a particular geographic location, there are limitations as to how much power can be transferred at certain points on the system.

The third area where reliability of electric service to the end user can be affected is in the distribution system. As described previously, the distribution system moves power at lower voltage from the transmission system down to the customer meter. Maintenance of distribution system reliability primarily entails having sufficiently sized distribution wires and voltage step-down transformers to handle localized customer loads, and maintenance and repair of distribution equipment (such as repairing downed wires due to accident or weather).

Maintenance of all three areas of reliability are necessary to achieve and maintain electricity reliability for the end user. An adequately sized and maintained distribution and transmission system is not enough if there is not enough power being generated to serve all customers' demands. Conversely, a glut of available generating capacity is not sufficient if the transmission or distribution systems fail and the power cannot be moved to the point of end use.

As we have described in this report, we do not envision the industry restructuring fundamentally altering the obligation of the electric utilities to hook customers into the system and deliver power to the meter. Accordingly, the responsibilities of the utility companies attendant to assuring safe and reliable distribution service will be fundamentally the same as today. The utility will continue to be obligated, pursuant to BPU regulation, to plan, size and maintain the distribution system in a manner that assures that power can be delivered at all times from the point of delivery off the transmission system to the end user.

Accordingly, we focus on potential impacts of restructuring on transmission system reliability and the reliability of supply. Specifically, it is clear that the traditional mechanisms for ensuring both short and long term system reliability are based upon the existing industry structure, and do not entirely comport with the competitive marketplace.

Currently, both short and long term bulk power system reliability in the Mid-Atlantic region is assured in the following manner, principally through the PJM power pool. The long term reliability of the transmission system itself, aside from its reliance on an adequate supply of generating capacity, is dictated primarily by long range planning to assure adequate power transfer capacity, as well as adequate maintenance and upgrades on transmission equipment. PJM and the member companies jointly perform such planning functions, including identification of the need for system upgrades or new transmission lines or equipment. Typically, the actual construction is undertaken by a utility or utilities in whose service area the facility will be located, but their is often joint ownership and/or shared capacity rights among the PJM member utilities.

The short term reliability of the transmission system is also currently the responsibility of the PJM power pool. On a constant basis, PJM and company system operators monitor the aggregate customer loads on the system, the operation and availability of individual generators, and voltage and current flow on all transmission facilities. In accord with the agreements signed by each of the utility members, the PJM control center has the ability to order any generator to reduce power output or to come on line to keep the system in balance and to maintain voltage and power stability. All generators per the PJM agreements are bound to abide by NERC[17] reliability standards. These are operational standards that generally provide for activities to be taken to assure the stability and safety of the system.

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[17] The North American Reliability Council (NERC) was formed to promote the reliability and adequacy of the bulk power supply of electricity. NERC achieves this goal through its ten regional councils, whose membership comprises virtually every utility in the country as well as a number in Canada, as well as, federal and rural electric cooperatives, municipalities, provincial utilities, IPPs and power marketers. These councils evaluate, for regional impact, the plans developed to meet future demand by the utilities, as well as the overall reliability of existing and future electric supply systems.

In addition, all member utilities have committed to mutual support in times of tight supply or system emergency. Accordingly, member utilities will bring on line all available generators, if necessary, to support the integrity of the system, even if problems originally arise because of another utility member's load or capacity. Ultimately, if generating capacity is not available to the pool in sufficient quantity to meet the aggregate load of the region's utility customers, the members have agreed to mutual support via system-wide voltage reductions (i.e. "brownouts") or, in extreme cases, shared load shedding (i.e. controlled, rolling blackouts) to avoid a system-wide collapse.

With respect to long-term reliability of generating capacity, each member electric utility is required to submit to the power pool long term forecasts of customer loads. Based upon these forecasts, there is a determination on a pool-wide basis of the amount of installed generating capacity which will need to be in place to meet reliability criteria. The planning criteria used is the "one day in ten year" loss of load probability (LOLP) which has been adopted by the Mid-Atlantic Council (MAAC), which is one of the regional councils that comprise NERC. This criteria means that the system is planned such that, based upon statistical analyses, the probability of "loss of load" occurrence (i.e. blackouts due to demand exceeding available supply) must be no more than one day every ten years. Based upon the LOLP calculations, a pool-wide capacity reserve margin is determined[18], with each member utility in turn obligated to contribute their assigned share of the reserve margin. The individual reserve margins assigned to each utility can vary somewhat depending on such factors as the historical outage rates of their generating units and the patterns of their customers' demands. Each utility must demonstrate to the pool, on a two year look-ahead basis, that it will meet its installed capacity requirements, or be subject to

[18] The capacity reserve margin is generally defined as the amount of installed capacity over and above forecasted peak system load. The recent historical reserve margin has been on the order of about 20%; meaning PJM has planned to have installed capacity which exceeds forecasted peak load by 20%.

financial penalties. Moreover, each state has its own laws, rules and/or policies in place to review the long term supply plans of the utilities.

The regional ISO, as envisioned by both the Board and by the FERC as set forth in its various Orders on the subject, will continue to have the responsibilities currently performed by PJM, as described above, concerning the maintenance of short-term bulk power system reliability.[19] This would include enforcement of applicable reliability standards on all generators participating in the regional marketplace. Importantly, it should be emphasized that there is no disagreement among the parties in this proceeding, including power marketers and independent power producers, that all suppliers should be required to abide by NERC reliability standards.[20] While the FERC will, as it does now, have primary regulatory oversight in this area, the Board will continue to have a close interest in those matters. Indeed, in order to emphasize the importance of this issue to the Board, it is our conclusion that we should require, as a condition for eligibility to serve retail electric customers in the State, that third party suppliers commit to meet all NERC (or successor) reliability standards.

Moreover, we envision that the ISO, in appropriate collaboration with regional stakeholders, will take on the primary transmission system planning function currently performed by PJM. Utilities, or other third parties, will actually undertake transmission

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[19] As pointed out in an earlier section of this report concerning the transition from wholesale competition to retail competition, these responsibilities will become more complex and required enhanced infrastructure as the number of transactions being conducted will increase many fold over the current market structure.

[20] It should be noted that the NERC is a voluntary industry organization. The FERC is currently considering whether, as part of industry restructuring, there is a need for mandatory, national reliability standards.

facility construction and maintenance, with costs being reimbursed by the ISO via transmission charges imposed on system users by the ISO.

The primary remaining focus in terms of reliability then, is on the long term reliability of generation supply. As described above, adequate long-term supply is currently dictated by a very centralized, planning process based upon long-term forecasts of utility customer loads, plus a mandated reserve margin. It is generally agreed that this centralized planning system is poorly suited, and indeed is incompatible with a competitive market structure. Utilities traditionally have had a monopoly on providing electric supply to customers in a defined geographic region. As such, the margin for error in load forecasts was driven primarily by uncertainties in macro factors such as economic growth and weather, as well as the penetration of energy efficiency. Conversely, for third party suppliers operating in a competitive marketplace, with no monopoly territory and whose customer base will be dictated solely by their success in the marketplace, it becomes impractical to undertake long-term load forecasts, and to commit to a specific assigned capacity portfolio on a two year ahead basis.

The question then is, what will replace the historical centralized planning function as the mechanism for ensuring the availability of adequate generating supplies in the long term. While perhaps not an immediate issue because of the general surplus of capacity available in the market today, this is an issue which must be addressed as we move into the future. Many in this proceeding have argued that the electric supply market will function like all other competitive commodity markets. That is, as supply begins to tighten, market prices will begin to rise, thereby providing the signal for suppliers to commit the capital to construct new production facilities. The key, it is argued, is to let the market work without government interference, such as price controls and the like.

We generally concur that in order for a market to properly function, it must be allowed to function. Accordingly, as has been the case in other competitive industries, most notably the natural gas supply industry, market signals can and will provide the primary impetus for construction of new production capacity to meet growing demand. However as we have described, uninterrupted, reliable electric service is an absolute necessity. Moreover, while there is no reason to expect that the electric power industry cannot function like other competitive commodity markets, the industry does have some unique characteristics. Most notable is the absolute necessity that electric supply be in exact balance with demand at every instant in time, and the fact that electricity as a commodity cannot be stored (certainly not in large quantities).

As a result, some have argued that the ISO must institute mechanisms to assure that adequate capacity will be in place. Such mechanisms could include a bidding system to procure capacity reserves. Another mechanism, such as that employed in the United Kingdom, would have the ISO set a value for loss of load, and use this in the form of an adder to adjust the spot price to send an explicit price signal for the need for new capacity. Yet another mechanism, currently being developed for the California marketplace, is called "demand bidding." In this mechanism, specific information on the amount of electricity that will be used at various prices is collected from aggregators and large customers. It is argued that this mechanism properly internalizes so-called shortage cost, and provides for stable capacity additions without the need for a separate capacity market.

This is an area which we will require be specifically addressed in each utility's filed restructuring plan. To wit, we will entertain proposals on the best manner to assure that there will be adequate generating capacity in the future to meet future customer demands, consistent with our conclusion that reliability cannot and must not suffer as we move to a competitive power market. We note that some change to the existing two years forward, methodology is necessary, and that this is likely to be a region-wide issue.

G. Jurisdictional Issues

An important issue arose during the course of this proceeding concerning the divide between State jurisdiction as exercised by the Board and federal jurisdiction as exercised by the FERC. The issue also arose during the FERC's Open Access rulemaking proceeding in a number of areas pertaining to the separation of the regional power network into transmission facilities subject to FERC ratesetting oversight and distribution facilities subject to State ratemaking. In its Order 888 the FERC made a number of findings concerning jurisdictional issues that the Board found objectionable, and by letter Motion dated May 23, 1996, the Board filed for rehearing in which we requested reconsideration of the following findings:

1) that the FERC is the primary forum for addressing the recovery of stranded costs caused by retail turned wholesale transactions (so-called "municipalization");

2) that the FERC has jurisdiction over all unbundled transmission in interstate commerce, whether the customer receiving the unbundled service in interstate commerce is a wholesale or a retail customer;

3) that the FERC has claimed dual legal authority, along with the states, to address stranded costs that result when retail customers obtain retail wheeling, ostensibly serving as a backstop to state action or inaction on retail stranded costs; and

4) that the FERC, while adopting a policy of "State deference" in the determination of the so-called "bright line" between transmission and local distribution, has adopted a seven-part test to judge such determinations which may be unworkable in many instances.

In its Order issued on March 4, 1997 the FERC rejected the arguments of the BPU and other State commissions and denied the motions for rehearing in this regard. Accordingly, there is some uncertainty as to the State's ability to set appropriate stranded cost policies and charges without federal intervention, were the State to provide retail customers with direct access to suppliers via open access transmission and distribution lines. This is one of the cited benefits of the poolco industry model according to PSE&G, specifically that by maintaining the local public utility as the exclusive seller of power from the competitive power pool, the State maintains clear jurisdiction over these retail transactions, and over the ability to impose "wires" charges. It has been argued that to do otherwise would risk customers or suppliers attempting to end run State jurisdiction and bypass certain State-imposed wires charges.

Although we share the concern expressed by PSE&G, we do not believe that this jurisdictional issue should drive the determination of an appropriate retail competition model. Rather, to the extent that we determine that direct retail customer access to suppliers (with a voluntary power exchange) is a preferable approach to introduce retail competition in New Jersey, we should seek clarity from the FERC on jurisdictional issues prior to the implementation of restructuring in New Jersey to ensure that the State will maintain the same degree and extent of regulatory jurisdiction over distribution services and related retail ratemaking in a restructured industry which it now exercises as part of its regulation of bundled electric utility services.

Specifically, we believe it incumbent on the State to inform the FERC of its final determinations on industry restructuring, and to seek and receive specific declaratory rulings from the FERC making clear the State's jurisdiction to establish wires charges and other unbundled retail service charges as described elsewhere in this document.

Moreover, to the extent that the FERC will not offer such clarification, there is a need for federal legislative action, perhaps most effectively within the context of national restructuring legislation, to provide some clarity on these jurisdictional issues to ensure the State's sovereignty in these areas.

VI. Energy Taxes

Electric and gas utility rates in New Jersey currently include the State Gross Receipts and Franchise Tax (GR&FT). This tax, which is collected on a per unit (kilowatt-hour) basis, represents about 13% of electric and gas utility revenues. As described earlier in this report, the GR&FT tax rate, which is among the highest in the country, contributes to the non-competitiveness of utility rates in New Jersey relative to national and other regional averages.

The Whitman Administration, recognizing the need to do its part to lower energy rates, has proposed a reduction of the current energy tax rate by 45% over a five-year period. Moreover, the proposal released in November 1996 recommends various changes, described below, to modify the energy tax policies in the State to conform with the changes taking place in the natural gas and electric power industries.

Under current State law, a minimum of $685 million in annual GR&FT revenues is guaranteed to be returned to the State's municipalities. The formula used to allocate these funds among the State's 567 municipalities is based in substantial part on the value of utility equipment located within each town. GR&FT distributions represent the second largest funding source, behind only property taxes, for the municipalities. Accordingly, GR&FT revenues have a direct bearing on municipal property taxes. In 1995 GR&FT revenues collected by the State via utility rates totaled some $1.197 billion. Of that amount, $782 million was distributed to the municipalities.

GR&FT taxes are not assessed nor collected on wholesale energy transactions. Moreover, these taxes only apply to utilities; accordingly non-utility sellers of energy, such as natural gas marketers and cogeneration facilities, are exempt from GR&FT. However, these entities pay various taxes from which the utilities are exempt as well as other taxes which are paid by utilities. These taxes are:

Corporate Business Tax
Sales and Use Tax
Real Property Tax

As a result, entities which in many cases are, or soon will be in direct competition with each other have differing tax burdens. This results in an unfair tax advantage which may skew the competition. As competition increasingly permeates the energy industries, it is imperative that these tax advantages be eliminated, and that the playing field be levelized.

In late 1994, the Board approved programs for each of the State's gas utilities to unbundle their rates, which provided the State's 230,000 commercial and industrial utility customers the ability to purchase natural gas transportation services from the utility, and to buy the commodity from other non-utility entities in the marketplace. The natural gas sold by non-utility marketers and brokers to customers is not subject to GR&FT. This provides a built-in savings to customers who switch from the utility as their gas supplier[21]. Because retail sales by non-utility suppliers are not subject to GR&FT, not only does this represent a competitive advantage, but it also results in a tax revenue erosion as customers switch from a utility to a non-utility supplier. To date over $230 million per year in sales from non-utility entities have been made and the State has lost over $30 million per year in GR&FT by virtue of customers switching suppliers. Were all eligible commercial and industrial gas customers in the State to switch to non-utility suppliers, the total exposure in lost GR&FT to the State is about $78 million annually.

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[21] GRF&T is still charged on the transportation component of gas service, which is provided by the utility.

The Board has recently approved pilot programs to provide small segments of residential gas customers the opportunity to purchase natural gas from non-utility suppliers. These programs are being implemented in the Spring of 1997. Should competitive opportunities be opened up in the future to all residential gas customers, a significant portion of the $207 million in GR&FT collected by the State from these customers could be put at risk.

As described in this report, the Board is proposing a phased introduction of supplier choice for electric customers in the State beginning in late 1998. Under current energy tax law, as retail competition is opened up and electric customers are provided the opportunity to switch to non-utility suppliers, the State stands to lose a significant portion of the $875 million in GR&FT currently collected from electric utility customers. These figures clearly dwarf the fiscal impacts of natural gas competition discussed above and, if remedies are not implemented, this could have significant fiscal impacts on municipalities as well as the State.

It is for the these reasons that the Board regards as essential to the efforts to introduce retail electric competition in New Jersey, a reform of the energy tax policies in the State. Indeed, in the "Joint Task Force Report On Energy Tax Policy," released in November 1996 by the Board of Public Utilities and the State Department of Treasury, specific energy tax reforms were proposed. The proposed reforms are intended to levelize the tax playing field among competitive energy suppliers in the State in both the retail and wholesale markets, as well as to prevent the severe tax revenue erosion which would result under the current system when retail electric competition is implemented. The Joint Task Force Report recommends replacing the existing GR&FT tax on utility rates with the imposition of two taxes, applicable equally to all energy suppliers, as well as a transitional tax (TEFA) paid by all users of the utility distribution system for a limited number of years. Specifically, utilities would pay the State corporate business tax (e.g. income tax) as do all other entities doing business in the State, and the State sales tax of 6% would be collected on all retail sales of energy services, whether provided by a utility or non-utility entity. The TEFA will be set to ensure that, at the outset of tax reform, the overall tax revenues collected will remain the same as under the current system. As well, the Joint Task Force Report proposes a gradual phase-out of the TEFA over a five year period which, upon completion, would reduce the total energy tax burden on utility customers by about 45% (the remaining imposition of the sales tax and corporate business tax would produce a total tax burden of about 7%, as compared to the current GR&FT tax rate on utility sales of 13%). These lower overall tax rates would be flowed directly through to customers in the form of lower electricity prices.

Bills which would put into law the primary components of proposed energy tax reforms - S.30 and S.31 and A.2824 and A.2825 - were introduced into the State Legislature in March, 1997. The companion bills provide as well for funding and allocation of energy tax revenue to ensure that municipalities are held harmless as the energy tax system is restructured.

Again, the Board strongly emphasizes the need for energy tax reform in the context of the restructuring of the State's electric power industry.

VII. Stranded Costs

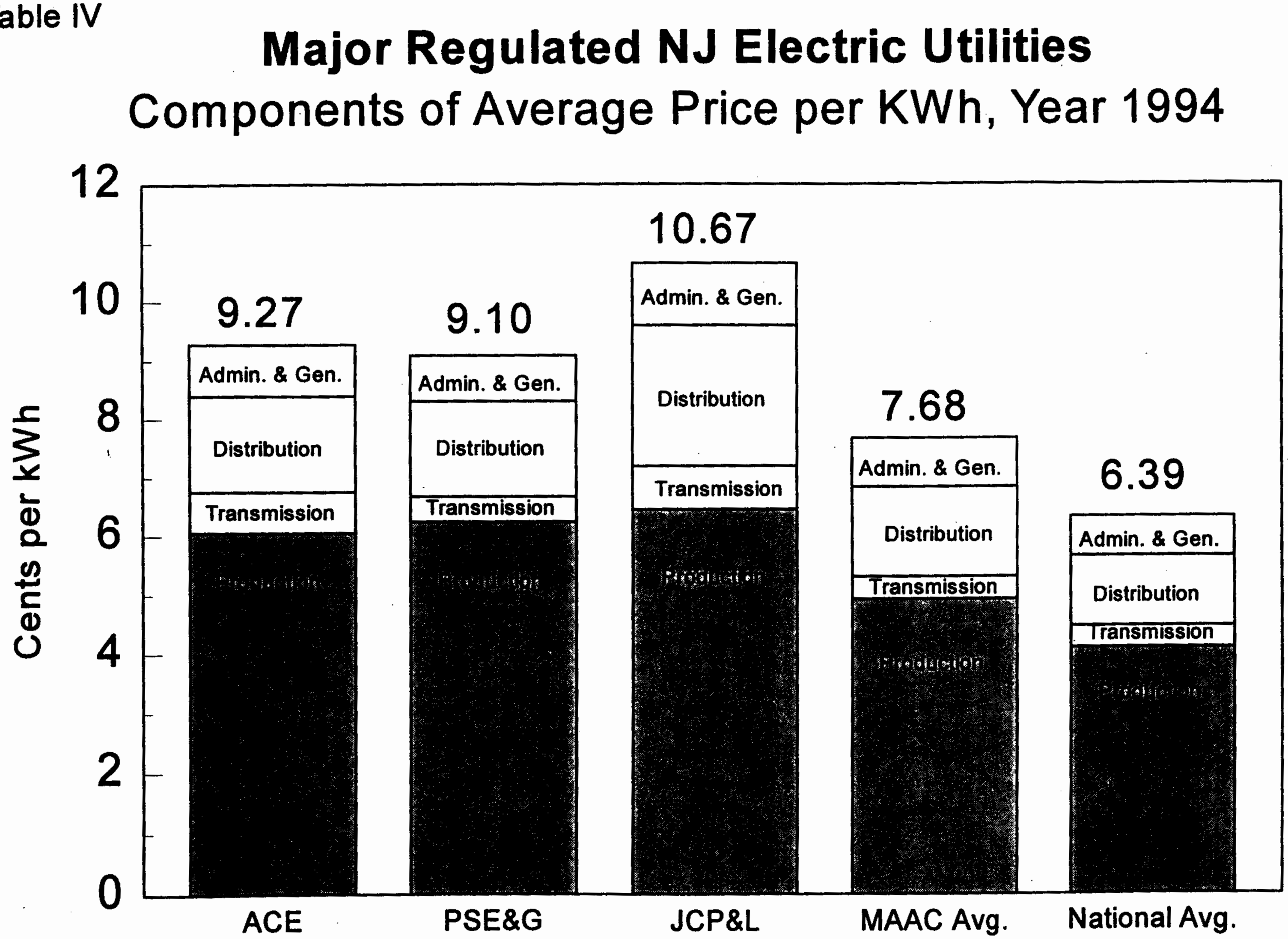
A. Identification of the Problem: What Are Stranded Costs?

As we described earlier in this report, the developing competitive market has made power available today in the wholesale market at prices substantially below the production costs currently reflected in utility rates in the State. It is expected that when the retail market in New Jersey is opened up to competition, consumers will have access to power at prices below current utility costs.

To develop an appreciation for the potential savings associated with a competitive power production market, it is useful to review the various cost components which comprise the current electricity bill paid in the State.

The cost of power production, that is, the current investment and operating costs of utility power plants, is by far the largest component of electric utility rates in New Jersey. As shown in Table IV below, the average cost of power production, at about 6 cents per kilowatt-hour, makes up about 60% of the total average bill paid by New Jersey consumers. Conversely, the total cost for transmission and distribution services, plus customer services and overheads (services which will still be provided by the utility and which will remain regulated), is about 4 cents per kilowatt-hour.

Table IV



Major Regulated NJ Electric Utilities
Components of Average Price per KWh, Year 1994
Cents per kWh
0
2
4
6
8
10
12
9.27
9.10
10.67
7.68
6.39
Admin. & Gen.
Distribution
Transmission
ACE
PSE&G
JCP&L
MAAC Avg.
National Avg.

It has been estimated that, were customers to have access to competitive power supply alternatives, they would be able to obtain such supplies at significantly lower costs. Estimates of the cost of power available today on the open market vary widely, but for these purposes we have assumed, consistent with the Status Report, a range of from about 2 to 4 cents per kilowatt-hour, as compared to the current utility cost of about 6 cents. Were power to be obtained at such prices, this could reduce the total price for electricity, including the cost of transmission, distribution and customer service, from its current 10 cents down to anywhere from 6 to 8 cents per kilowatt-hour.

While these potential savings are the primary reason that we and other states advocate opening the retail electric markets up to competition, paradoxically they also underlie perhaps the most vexing issue that we face during the transition period. As prices paid to power suppliers in a competitive marketplace are market-driven, a utility may expect to receive only the market price for power in the future. As indicated, it is expected that this market price will be substantially below the average production costs of utilities currently embedded in rates. Accordingly, in a competitive marketplace utilities will be unable to recover all of their so-called "embedded costs," that is, the costs associated with past commitments currently included in regulated rates. The amount by which the embedded cost of utility service exceeds the market price for that service, which is therefore regarded as "uneconomic," is generally referred to as stranded costs. Taken another way, stranded costs can be regarded as the potential shortfall in revenues, or "loss," which could be experienced by the electric utilities as competition is introduced and their traditional monopolies are opened up to competitors.

The specific issue with which we are faced, and which regulatory commissions and legislatures throughout the country are currently grappling, is the extent to which utilities, during the transition period from monopolies to competition, should be permitted to recover from ratepayers these otherwise "stranded" costs via bill surcharges or so-called "exit fees."

B. Stakeholders' Points of View

Having discussed and identified what stranded costs are, we now turn to perhaps the most problematic issues concerning stranded costs, specifically stakeholder responsibility, recovery mechanisms, and mitigation. As well, we will discuss in the following section the specific categories of stranded costs.

During this proceeding the Board has received on these issues perhaps the widest range of opinion on how much, if at all, particular stakeholders should contribute towards the stranded costs created as a result of the introduction of retail electric competition. Following are some of the highlights of those arguments.

The utilities argue that they should be entitled to the full and timely recovery of stranded costs. They argue that they were granted certified territories for which they accepted an obligation to serve, develop and maintain the necessary electricity infrastructure to provide universal service to all customers within a given territory. In exchange, it is argued, they were promised by regulators a fair opportunity to recover the reasonable cost of the financial commitments incurred to satisfy their public service obligation. This implicit relationship between regulators and utilities has generally been termed as the "regulatory compact."

The utilities argue that these costs are already in retail rates because they have been found to be prudently incurred in accordance with the utility's obligation under current regulation to serve all customers. These costs represent prudent investments and commitments made as part of the regulatory compact that their shareholders have relied upon as they made their continued investments into the electricity infrastructure over the years.

The utilities advocate that any restructuring of the electric industry should continue to be based on the principle that shareholders are entitled to recover the investments prudently made under the old regulatory regime (including a reasonable return) from the customers base on whose behalf those investments were made. It is for this reason that the utilities advocate that all of these cost should be included as part of the stranded cost definition. They opine that for regulators to reverse course and now limit the utilities' earnings on their past investments to what they can garner in a future competitive marketplace would breach the regulatory compact, decrease economic efficiency, threaten viability and reliability of an essential infrastructure industry, and constitute an unlawful taking of property. Specifically, the potential economic dislocations resulting from an inability to recover stranded costs include massive write-offs, a downgrading of utility debt which could hinder the utilities' ability to attract new capital, and large-scale cutbacks in utility jobs. If extreme measures were to be taken in terms of denying stranded cost recovery, even bankruptcy could be a possible result. The utilities urge the BPU not to permit such a result.

The small consumers advocates, on the other hand, argue that if residential and small business consumers are asked to bear the burden for stranded costs, it is unlikely that they will enjoy the opportunity for lower rates in the near future. They advocate that utilities must not be guaranteed the recovery of costs associated with uneconomic assets and should bear the major responsibility for stranded cost. They indicate that recovery of stranded costs only rewards the inefficient utilities, unfairly holds ratepayers responsible for poor utility decisions, and ignores the risk inherent in all utility investments. The bottom line is that the consumer groups wish to see an immediate and substantial reduction in utility rates now, not some time in the future. Recovery of even a portion of stranded costs should only be considered if a utility demonstrates by opening its books that bankruptcy would otherwise result.

The industrial users also express a strong desire that they gain the benefit of competition through lower rates. While they do concur with the view that a regulatory compact does exist, they query what the regulatory compact says, if anything, about stranded cost recovery by utilities that have been forced to leave their regulated environments and enter the competitive world. Additionally, the industrial users do not believe that the regulatory compact was ever intended to protect the uneconomic investments of utilities.

The industrial users took the position that there should be some sharing of the burden of stranded costs between utility shareholders and ratepayers. The industrial users do not believe that a precise sharing formula should be established on a generic basis for all utilities. Rather, an analysis should be made as to the nature, extent and cause of stranded investment on a utility-by-utility basis, and there should be an "equitable" sharing of unmitigated stranded cost. They also feel that as a condition to allowing a utility to recover any stranded cost, it should first be required to demonstrate that it has taken all reasonable actions to mitigate and reduce the level of its stranded cost.

Independent power producers (IPPs) are uniquely positioned in this debate, being both suppliers to electric utilities as well as being potential competitors. The IPP position on this issue relates primarily to non-utility generation contracts. They insist that the sanctity of all power purchase contracts previously approved by the Board must be honored as a matter of law. They indicate that IPP investors who made commitments must be able to rely upon a transition policy that respects the sanctity of non-utility contracts and provides for full recovery of IPP costs by utilities. IPPs indicate that their argument is based on the fact that these contracts were entered into in good faith and to the mutual satisfaction of both parties at the time they were executed.

The IPPs argue that if the Board wishes to encourage companies to enter a future competitive energy marketplace with confidence in the underlying rules, it is essential that it clearly acknowledge the sanctity of all IPP contracts approved by the Board. IPPs indicate that the foremost consideration for their investors, lenders and project sponsors is simple: who will trust tomorrow's deal if yesterday's is not honored.

The Division of Ratepayer Advocate argued that the claims of utilities that the "regulatory compact" has created a "right" to compensation of 100% of stranded costs is incorrect and based upon a distortion of regulatory law and economics. They feel the regulatory compact simply provided that in exchange for accepting a limited service territory, within which it would be granted monopoly rights, the utility would agree to accept restrictions on its sale of products (including, but not limited to price) set by a regulatory compact, rather then by market forces. The courts have applied this regulatory compact to prevent the destruction of existing values, such as where a utility commission would require the provision of service by the utility at an unreasonably low rate.

The Ratepayer Advocate has taken the position that stranded costs should be shared between ratepayers and utility shareholders, since stranded cost are due to the emergence of retail competition in the electric industry, a change not caused by ratepayers or utilities, yet both must live with it. The amount utilities should be permitted to recover should be determined on a case-by-case basis, although they put forth as a reasonable starting point a 50%-50% cost sharing of stranded cost as a guide to the disproportion of any stranded cost. They feel it is fair and reasonable that both parties should bear a part of the transition by sharing stranded costs. However, this sharing must only be for a limited period, and of a limited amount.

C. Breakdown of Stranded Cost Categories

1. Causes of Stranded Costs:

The issue of stranded cost was studied extensively by a working group comprised of a cross-section of interests, whose final report was summarized in the May 1996 Status Report. That working group identified a number of potential causes of stranded costs, including:

* **Regulatory actions**- these would include actions by regulators to permit retail customers to bypass utility generation to choose their supplier of power, as well as mandates that may change utility pricing from cost-based to market-based.

* **Customer-installed self generation and demand side management (DSM)**- these actions by customers could reduce customer consumption, thereby reducing overall revenue contribution towards utility assets.

* **Customer relocation out of the utility's service territory**- such actions by customers result in a loss of contribution towards utility assets. Under current regulation, such lost revenues are netted against net revenue increases from new customers and prospectively recovered from remaining customers in future rate cases.

With respect to the potential causes of stranded costs, for purposes of this report, we deem it appropriate to focus primarily on regulatory actions. Specifically, what we must address are those stranded costs which are or may be created as a result of the recommendations in this report to open the power generation and supply market up to competition.

While customer relocation can result in a loss of revenues for the utility, this is by no means a new phenomenon. Customers have moved in and out of a utility's service territory continuously for a variety of reasons, and will continue to do so. There is no need as part of this restructuring proceeding to create special mechanisms to address this situation.

The situation with self generation and DSM is somewhat different. First, with DSM it is true that the installation of high efficiency equipment at customer sites can reduce utility revenues. However, in its DSM rules (N.J.A.C. 14:12) the Board has already provided a mechanism for utilities to recoup lost revenues resulting from DSM, as part of our effort to remove barriers and disincentives to implementing energy efficiency technologies. No further action is required at this time.

With respect to self generation, this too, is not a new phenomenon. Over the years, certain industrial and commercial end users have installed on-site generation facilities, either as a means of displacing more expensive purchases from electric utilities or simply for providing enhanced reliability, for example when a hospital installs backup generators. It is true that technological developments have made on-site generation more feasible. However, again this may be more a function of changing technology, rather than a deliberate action by a governmental body which causes financial exposure to utilities. An argument has arisen, however, that to avoid responsibility for stranded costs self-generation may be hastened by the imminent prospect of a restructuring decision by this agency or the State. Accordingly, pending regulatory action may give rise, if not directly then indirectly, to the installation of customer self-generation. Indeed, PSE&G has recently filed a separate petition with the Board requesting approval of an interim charge, to defray the losses which utilities and ratepayers may allegedly experience as customers leave the system now, in anticipation of a restructuring plan which may impose exit fees or surcharges on departing customers. We have determined within that proceeding (BPU Docket No. ET96090669) to expand the matter to a generic review, not only with respect to the imposition of an interim charge, but also with respect to the long term policy issue of whether to impose stranded cost surcharges on customers switching to on-site generation. After allowing for appropriate public input we will render a final policy pronouncement on the issue of exit fees.

2. Sources of Stranded Costs:

The working group report identified the following potential sources of stranded costs:

* **Utility-owned generation;**
* **Long and short term power purchase agreements with other utilities;**
* **Long term power purchase contracts with non-utility generators;**
* **Utility regulatory assets; and**
* **Other: down-sizing and restructuring costs, social policy programs and stranded benefits.**

Because of the current high level of electric utility costs, the magnitude of the potential stranded costs of New Jersey electric utilities is substantial. The working group report, summarized in the Status Report, provided a range of estimates of the stranded costs for each utility by major category. The range is quite wide, depending most specifically on the assumed future market price for power. For the reasons described previously, the magnitude of a utility's stranded cost is inversely related to the actual market price for power; i.e. the lower the market price, the more of the utility's current costs will be "uneconomic." The range of State-wide stranded costs, broken down by major category, was as follows:

	Low	High
Utility Plants:		
Nuclear	$4.0 billion	$7.0 billion
Steam & Other	(2.0)billion	$2.9 billion
Purchase Contracts:		
Non-Utility	$3.5 billion	$5.3 billion
Utility	$0.1 billion	$0.1 billion
Regulatory Assets:	$1.5 billion	$1.5 billion
Total:	$7.1 billion	$16.8 billion

While we emphasize that the working group numbers represent as-yet untested estimates, it is evident from the table above that the large potential magnitude of utility stranded costs in the State is driven to a large extent by two factors: high cost utility-owned nuclear power plants and high-priced supply contracts with non-utility generators, (otherwise referred to as independent power producers (IPPs)), in comparison to expected market prices. Depending on whether the low or high end range of estimates is used, nuclear power accounts for about 40-55% of the total stranded cost problem; IPP contracts account for anywhere from one-third to one-half of the estimated stranded costs. Taken another way, the lion's share of high cost power generation built into current rates in the State relates to nuclear power plants and IPP contracts.

We hasten to emphasize that these are State-wide figures, and that individual utilities all have their own various characteristics. For instance, at the high end of assumptions, nearly two-thirds of Atlantic Electric's estimated stranded costs are related to contracts with independent power producers. Conversely, for PSE&G high-priced IPP contracts represent a relatively small portion (14%-30%) of total estimated stranded costs, with nuclear power comprising anywhere from 57%-100% of the problem.

We discussed in the previous section the potential causes for the creation of stranded costs which need to be specifically addressed in this report, specifically, narrowing them down to regulatory actions which open traditional monopoly utility services up to competition. Further, we set forth above the potential magnitude of stranded costs. We now turn to a discussion of the various potential sources of stranded costs identified. In so doing, we recognize that there is a linkage between the causes for stranded costs and the need to specifically address the various potential sources of stranded costs. Specifically, it is our opinion that eligibility for stranded cost recovery, as will be described more fully below, should be limited to those costs which would otherwise be unrecoverable as a direct result of our decision to open the power generation market up to competition.

As a result, we would limit the eligibility for stranded cost surcharge recovery to costs related directly to utility power supply. More specifically, we would include as eligible costs for inclusion in a stranded cost charge the following categories:

* **Utility generation plant.**
* **Long and short-term power purchase contracts with other utilities.**
* **Long term power purchases contracts with non-utility generators.**

We conclude that the other identified potential sources of stranded costs, including regulatory assets, down-sizing and restructuring costs and social program costs, are not directly put at risk through the introduction of competition into the retail power generation market, and can be addressed through more traditional ratemaking techniques. Moreover, as generation-related stranded cost charges will be a transitional, non-permanent tool, as opposed to these other categories which may require longer term commitments, this is further basis for concluding that identified "other" categories are not appropriately recovered in a stranded cost charge.

For example, the amortization of regulatory assets, which represent anywhere from 9 to 21% of potential stranded costs, is currently recovered via the regulated base rates of electric utilities. It is our conclusion that this should continue to be the case; with regulatory assets, including those associated with a generation expense, being recovered via the regulated base rates (i.e. distribution charges) of the utility. This would apply to those regulatory assets which are already being recovered in rates, as well as those currently on the utilities' balance sheets as a result of prior Board Orders but not yet being

Moreover, it is the operation of the nuclear power plants over their entire lives, including past operation from the date that power production commenced, which contributes to the need to ultimately render in a safe condition and dismantle these plants. Accordingly, it is appropriate that all current customers continue to contribute towards these costs. We therefore conclude that two basic principles must be adhered to regarding decommissioning costs: 1) that since a stranded cost charge is a non-permanent, transitional tool, this is not the appropriate mechanism to fund nuclear power plant decommissioning, which we see as a long-term funding commitment; and 2) that decommissioning costs must be recovered via a non-bypassable charge assessed by the utility which is paid by customers regardless of their choice of supplier.

D. Stakeholder Responsibility for Stranded Costs

With regard to stakeholder responsibility for stranded costs, each of the arguments summarized previously have elements which we find persuasive, which is what makes this issue particularly vexing. Arguments that could compel us to conclude that utility investors relied upon our past decisions and the regulatory compact in committing to new generating sources, and that it would be unfair and disruptive to financial markets if we were to disallow future recovery of those investments rendered uneconomic by virtue of our decision to subject traditional monopoly electric utility markets to competition, are not without some merit. However, a strong point is also made that utility investors have earned reasonable rates of return on their utility investments, and those returns reflect some degree of business and regulatory risk, and that future returns are not protected or guaranteed. Moreover, we cannot ignore the consumer and customer argument that putting all of the responsibility for stranded cost recovery on the ratepayers will effectively preclude any near term benefits to the customer as a result of competition.

Moreover, as described in the Energy Tax section of this report, the State has proposed modifications to State energy tax policies which will over time reduce the overall tax rate on utility sales by nearly 50%, and commensurably reduce overall utility rates by approximately 6%. It is entirely appropriate that utilities be asked to contribute as well to the effort to reduce the current high level of utility rates in New Jersey.

Having thoroughly analyzed and considered the arguments presented, we conclude the following with respect to stranded costs. We believe that the electric utilities should be given an opportunity to recover from customers the costs associated with past financial commitments made by the utility for the purpose of procuring generating supplies to serve the retail electric customers in their service territory. However, we emphasize that this opportunity may be constrained by the achievement of other essential considerations, including the customers' right to pay just and reasonable rates and experience near term benefits from competition. It is our recommendation that such near term benefits should include at a minimum a 5-10% rate reduction. Accordingly, we specifically conclude that there neither can nor should be a guarantee provided for 100% recovery of stranded costs. Among other reasons, we believe that the provision of a guarantee for recovery of all uneconomic costs, by holding all utilities completely harmless to the effects of competition, would take away all benefits for a utility(s) which may have been more successful than others in controlling their generating costs. This, we believe, would be an unfair and inappropriate result.

We must elaborate on the benchmark to be employed when determining whether a particular cost relates to a "cost associated with past financial commitments made by the utility, for the purpose of procuring generating supplies to serve the retail electric customers in their service territory." First, we focus on what we mean as "past" commitments. Some have argued that all generating costs incurred up to the date of the issuance of this report, when specific conclusions on retail competition are reached, or even up until the date when utilities are actually being released of their obligation to serve all customers should be eligible for stranded cost recovery. We disagree. First, given the developments at the federal level and in other states throughout the country over the past few years concerning the transition to competition, as well the policy pronouncements by this agency in the Phase I Energy Master Plan report and the issuance of our Order initiating this proceeding a year and half ago, it cannot be reasonably argued that decisions made even through 1996 were made with the expectation that the utility would have long-term immunity to competition. Moreover, we point out that the electric utilities in this State have been on specific notice for several years of the changing paradigm for future generation commitments. In a series of Orders issued in 1994 and 1995, Docket No. EM91010067 and Docket No. EX94120578, the Board specifically indicated that new commitments to supply resources would not be judged on a traditional prudency basis, but instead must be subjected to a market test. The most recent of these Orders even specifically put the utilities on notice that they should not create any new potential stranded costs. Indeed, as early as in July 1993, a report was issued by the Advisory Council on Electricity Planning and Procurement, chaired by Commissioner Carmen Armenti, recommending that future supply commitments made by utilities be done through competitive bidding procedures.

While the referenced documents perhaps emphasize newly acquired generating resources, the concept of market-testing of new commitments applies equally to major investments in existing generating resources. In other words, electric utilities should have been assessing major upgrades to and investments in existing generating facilities, such as repowering projects, in light of competitive supply options available.

In light of the foregoing, as well as the fact that the electric utilities in the State all had their last base rate case, where all investments judged at that time to have been prudently incurred were permitted to be recovered in rates, in the early 1990's relatively soon before the issuance of these "market test" documents, we conclude the following. The presumptive cutoff point at which generating assets would be eligible for recovery via a stranded cost charge would be those costs which have been committed to and reflected in rates up through the conclusion of the utility's last base rate case prior to the issuance of this report. Accordingly, costs for utility generating plants not currently being recovered in rates would not be eligible for designation as stranded costs, and for related recovery under a special customer surcharge.

We would entertain requests for recovery of costs incurred after the conclusion of a utility's last base rate case; however there would be a substantial shift in the burden of proof which must be met by the utility, reflecting the fact that there is no presumption of recovery eligibility for costs incurred after the last base rate case. Specifically, the burden would be on the utility to demonstrate that it had no more cost-effective resource alternatives available to it at the time it made the commitment, including evidence of a market test to determine available alternatives.

Except as provided for in the section of this Report describing Basic Generation Service, any generation cost incurred after the commencement of retail competition would be fully subject to market risk. However, in no event would such costs be eligible for stranded cost recovery.

We note that the above refers specifically to utility-owned generation. Commitments to purchase power from non-utility generators must be treated somewhat differently. IPP contracts are traditionally reviewed and approved on an individual basis, outside of base rate cases. Accordingly, subject to mitigation strategies discussed below, the non-mitigatable costs associated with all such contracts which have previously been reviewed and approved by the Board, notwithstanding the specific date, must be eligible for stranded cost recovery.

E. Mitigation of Stranded Costs

All parties to this proceeding agree that every stakeholder should make a reasonable and good faith effort to mitigate stranded costs in order to ease their impact on rates. However there are different opinions among parties as to the methods to mitigate stranded costs.

The utilities believe that mitigation of stranded costs to the extent possible is in the best interest of all stakeholders. However, they believe mitigation should only be voluntary, and incentives should be developed by the BPU that encourage mitigation of stranded costs.

The Ratepayer Advocate indicates that utilities should make all reasonable attempts to mitigate uneconomic costs, for example be renegotiating purchased power contracts or by lowering the total operating costs of plants where it is safe and economic to do so. Thus, any calculation of stranded costs should reflect such mitigation efforts. Stranded cost eligibility should be limited to only those costs which are truly unavoidable.

Several power marketers and industrial users support the concept that stranded cost recovery by utilities should be conditioned on the utility's using its best effort to mitigate its stranded costs. They recommend that each public utility seeking stranded cost recovery should be required to submit a mitigation plan to the BPU to assist the Board in determining the amount of stranded cost recovery for that utility. They also support incentives being developed to encourage utilities to mitigate its stranded costs.

Several IPPs indicate it is unlikely that IPPs will be able to assist the utilities in the mitigation of their stranded costs, and renegotiate their existing power purchase agreements voluntarily and on a "win-win" basis, unless IPPs have an efficient market in which they can sell their power. Other IPPs encourage the voluntary renegotiation of contract terms by the parties to the contract.

Certainly utilities must, and should be obligated accordingly, to take all reasonably available measures to mitigate the stranded costs caused by the introduction of retail competition. Such measures may include, but are not limited to, the sale of excess generating capacity, accelerated depreciation of assets, reduced return on uneconomic assets, the buy-out or renegotiation of existing contractual power purchase agreements with non-utility generators, any tax implications, and the offering of other (non-generation) utility assets or services (such as addressed in the "Customer-Side Services" section of this report). The above would generally be regarded as mitigation measures taken to reduce the total pot of stranded costs which may be subject to sharing among the stakeholders. Moreover, since the potential losses which the Board is attempting to mitigate is the difference between book value of assets and market value beginning at the time rates are unbundled, it is appropriate to take into account the effects of depreciation of these assets since their inclusion in rates.

With respect to the IPP contracts, as described earlier, it has been argued that IPP contracts should be considered essentially untouchable, and be permitted to continue over their remaining lives at the specified prices. The primary basis for that argument is the decision of the U.S. Third Circuit Court of Appeals in Freehold Cogeneration Associates, L.P. v. Board of Regulatory Commissioners of New Jersey, 44 F.3rd 1178 (3d Cir. 1995) cert. den. 116 S. Ct. 68 (Freehold). case. In Freehold, this agency had begun an investigation of the previously approved power purchase agreement between the Freehold cogeneration facility and JCP&L. Specifically, after the contract was originally approved in 1992, the market price for power had fallen substantially, rendering the pricing in that contract unfavorable for ratepayers relative to other sources of supply which had become available. Because the project had not yet been financed and constructed, the Board felt it appropriate to consider various courses of action and explore a renegotiation or buy-out of the contract by JCP&L. The Board's actions were challenged by the project in court, and ultimately the Third Circuit ruled, based upon the facts specific to that case, that once the Board approves a power purchase agreement with a cogeneration facility on the grounds that the rates were consistent with avoided cost, just, reasonably and prudently incurred, any action or order by the Board to reconsider its approval or deny passage of those rates to the utility's customers under purported state authority was pre-empted by PURPA. Accordingly, the Freehold decision has been interpreted that, without legislative action at the federal or State level, a State regulator has minimal ability to subsequently adjust the pricing in such contracts once approved.

While we are loathe to even attempt to upset contractual arrangements, and consistent with the above decision, it appears that we have no jurisdiction to order such modifications, without some mitigation of high-priced IPP contracts it will be much more difficult to achieve any near term rate reductions. As described earlier in this section, high-priced with non-utility generators contracts contribute in no small way to the current high level of rates experienced in New Jersey. Indeed, the Status Report estimates attribute anywhere from 1/3 to 1/2 of the entire stranded cost problem in the State to above-market IPP contracts. Moreover, these contracts are primarily long term agreements (mostly 20 years and in some cases up to 30 years) with many years remaining. Of course, these long-term fixed-price contracts offered the prospect of risk-shifting from ratepayers to developers, as compared to traditional cost-plus ratesetting for utility generating plants. Moreover, cogeneration plants developed as a result of these contracts have provided economic development and environmental benefits. Nonetheless, in the future there will be no such disparity in the risk profile faced by different generators. Moreover, since cogeneration contract costs represent a significant portion of stranded costs, it will be difficult to obtain the desired near term rate relief unless a way is found to reduce the costs of these contracts. To date, with some limited exceptions, there has been very little evidence of serious attempts on the part of IPPs through voluntary negotiations to mitigate the relatively high prices being paid by utilities under these contracts.

We strongly encourage all stakeholders to renew their efforts to explore all reasonable means to mitigate IPP contracts. Moreover, this is an area which the FERC, the Congress and the New Jersey State Legislature may wish to review in order to provide an added impetus for parties to these contracts to seriously consider mitigation.

F. Securitization

A relatively recent mechanism to help address the stranded cost issue, which is now being explored in a number of other states, is the so-called "securitization" of such costs. Securitization essentially entails the financing of stranded costs, up to a defined limit, by issuing debt (so-called :asset backed securities, or ABS), and paying the interest and principal associated with the ABS through a surcharge levied on the utility's customers.

The ability to do this is typically established through enabling legislation, while determination of the types and amounts of the specific costs eligible for recovery is subject to regulatory commission approval. Following such approval, the utility transfers its right to recover a specific stranded cost to a "single-purpose grantor trust." This trust is an entity that structures and issues the ABS to investors, remits the proceeds from the sale of the ABS to the utility, and pays the interest and principal due from the monies collected by the utility. Importantly, while the issuer may be a state agency (ex. in California, the state Infrastructure and Economic Development Bank), these securities are not backed by the state; they depend solely on collections of funds through utility rates for the payment of interest and repayment of principal. Thus the utility effectively serves as a collection agent, and neither the debt nor the revenues appear on the utility's financial statements.

Because of the statutory ability conferred on the utility to collect these funds, including true-up mechanisms, the ABS are highly rated by bond agencies, typically triple A. This high rating carries with it reduced interest costs as compared to the utility cost of capital, including debt typically rated at single A or even triple B, and equity. This reduced interest cost can provide a benefit for ratepayers compared to the utility cost of capital built into current rates. Moreover, while interest on the ABS is not exempt from federal income taxes, it may be exempt from State income taxes if the ABS are issued by a State agency, as is the case in California.

On the other hand, it must be kept in mind that generating assets have fairly long lives, up to 40 years, and attendant lengthy write-down schedules in rates. If securitization of assets occurs over a shorter period of time, as has been suggested, this accelerated schedule could offset these interest cost benefits. Moreover, to insure that the sale of the right to the recovery of stranded cost to the trust as well as the revenues collected in rates are not taxable transactions, it may be necessary for the utility to consolidate its financial statements with those of the issuing entity for tax purposes. In that event, the ABS might not be considered "off balance sheet" financing, and could be taken into account by the bond rating agencies in evaluating the utility's credit-worthiness. If the securitization continues to be appropriately structured, however, the effect would not necessarily be negative, i.e. the rating agencies might still not consider ABS debt to be utility debt in the traditional sense.

There are examples of other states which have recently looked at securitization as a means of addressing stranded costs associated with electric restructuring. As referenced earlier in California, Assembly Bill 1890 was passed by the legislature in August 1996 and signed into law by the Governor in September. In addition to largely reaffirming the policies adopted by the CPUC for restructuring the state's electric power industry, this legislation authorizes the California utilities to securitize up to $10 billion of stranded costs, with terms up to 10 years. Coupled with the authorization, however, is a requirement that the utilities reduce rates to residential and small commercial customers by 10% effective 1/1/98, and an additional 10% reduction is anticipated by the year 2002.

In June 1996, legislation was introduced in New York that would allow securitization of assets by that state's utilities. The bill was passed by the State Senate; however final action is not expected until the next legislative session in 1997. Similar legislation was passed by the legislature and signed into law by the Governor of Pennsylvania in December 1996. Recognizing circumstances in their state, Pennsylvania did not establish a specific rate reduction target, but required that the potential financial benefits derived through securitization flow to ratepayers.

As discussed, there are a number of issues related to securitization which require further scrutiny, However, the concept holds the promise of helping to further reduce the impact on ratepayers of stranded cost charges, and to provide some immediate rate relief.

We emphasize, however, that securitization cannot be regarded as a panacea, only as part of a solution to the stranded cost problem. Moreover, securitization, as a relatively risk-free mitigation tool for utilities, cannot serve as the sole source of potential rate reductions. In addition, because of the nature of securitization, whereby proceeds may be utilized in rather large up-front lump sums, to buydown contracts or retire debt and equity on the basis of market price projections, we believe it advisable to put a limit on the amount of securitized debt which can be issued by each utility. We further emphasize that proceeds from the sale of securitized bonds must be utilized by the utility solely to reduce generation-related stranded cost, and not to subsidize any other activity of the utility.

Finally, in order to clearly demonstrate the rate reductions which might be achieved as a result of securitization, we will require that utilities, within their filings, provide a schedule of various MTC charges, both with and without securitization, and the related level of rate decrease.

G. The Need for Rate Relief

As we have emphasized throughout this report, the fundamental reason for restructuring the electric power industry in the State is to reduce the cost of electricity to New Jersey consumers. However, as described previously, the stranded cost problem in New Jersey is sizable. If all stranded costs are subject to guaranteed recovery from ratepayers, there could be a significant period of time before these uneconomic costs are written down, and actual electricity bill reductions are realized by customers, despite the availability of low cost energy in the market.

Conversely, despite our strong interest in achieving immediate rate relief for customers, as some have advocated, we do not believe that this can or should be achieved simply by denying outright any recovery of stranded costs. As described earlier, the stranded cost problem in New Jersey has been estimated to be on the order of $7 billion to about $17 billion in uneconomic assets. By and large, these represent costs that are already included in current rates. A decision on our part to deny outright recovery of these costs and effectively remove them from current rates would necessitate an immediate write-off of this magnitude which would undoubtedly result in severe financial consequences, including downgrades of utility debt leading to an impaired ability to attract capital and in extreme cases, even possibly bankruptcy. Moreover, such severe measures could also necessitate substantial reductions in work force by these major employers. This would be an irresponsible and reckless way to achieve the immediate rate relief of 20% to 25% which some have advocated.

While we will allow the utilities a conditioned opportunity to recover stranded costs, we will nonetheless expect that utilities take all reasonably available steps to mitigate stranded costs as described above. However, it is questionable whether such measures alone will sufficiently reduce the total pot of dollars such that New Jersey consumers will experience any noticeable rate relief in the near term. While it is neither reasonably achievable nor realistic to expect, as described above, an immediate lowering of rates on the order of 20% to 30%, we find the prospect of no near term rate relief to as well be unacceptable. While we are confident of long term benefits, we believe that the public has a right to demand some near term benefit from the breakup of the traditional electric utility system. Moreover, as discussed previously, the State has proposed modifications to the State energy tax system which would phase-in a 45% reduction in energy tax rates, resulting in an overall 6% reduction in utility rates. It is not unreasonable to expect other stakeholders to similarly contribute to the effort to reduce electricity prices in the State.

Securitization, while holding promise as a means of assisting in the solution to the stranded cost problem, cannot be regarded as a cure-all. Ratepayers will still be required to pay off this debt, albeit at an interest rate lower than the utility's cost of capital, over an extended period of time. As such, in evaluating the potential benefits of securitization it will be important to be mindful of the total cost to ratepayers over the life of the securities, and not simply focus on the short term effects.

While we have indicated our intent to provide utilities with an opportunity to recover all non-mitigatable stranded costs, we have provided no guarantee. Specifically we believe it appropriate, consistent with the overall purpose of restructuring, and in connection with any ability provided to utilities to securitize a portion of stranded costs, to set as a goal some lasting, rate reduction in the near term, concomitant to the introduction of retail competition. The individual circumstances of each utility differ in terms of the current level of their rates, the specific sources of stranded costs and opportunities for mitigation, and these circumstances must be reviewed fully within the context of individual utility restructuring and stranded cost filings. Accordingly, it would be inappropriate to devise a "one-size-fits-all" solution. However, we believe that the introduction of a near term rate reduction on the order of 5-10%, concurrent with the unbundling of rates and the introduction of retail customer choice and in conjunction with securitization, is an appropriate goal.

In response to concerns that these targeted rate reductions may be eroded by subsequent upward rate adjustments between now and the date of retail competition, we emphasize that the targeted rate reductions must be in comparison to the current level of rates as of the date of this report.

We do not believe it appropriate or consistent with the conclusions in this report for us to preordain any specific stranded cost sharing percentage between shareholders and ratepayers. Rather, we prefer setting specific rate reduction targets, and providing each utility the maximum flexibility to employ all available mitigation techniques, including securitization, to achieve that goal. In order to achieve a definitive rate reduction goal, this would implicitly mean that there would be a cap on the permissible stranded costs charge. Importantly, in order to ensure near term rate relief such a cap would reflect the aggregate of both the market transition charge as well as any separate surcharges associated with securitization. The implementation of such a cap would avoid the need for detailed regulatory "prudency" reviews of every actual or potential mitigation effort. Moreover, it would provide the maximum possible incentive for utilities to aggressively pursue mitigation.

We do not rule out a utility being able to recover all of its non-mitigatable stranded costs. Through past and future mitigation efforts, the utility may be able to offset all stranded costs within the cap. To the extent that the utility could recover all non-mitigatable stranded costs within this capped charge(s), consistent with the long as well as near-term interests of customers, that would be a satisfactory result.

We note however, that an MTC should not result either directly or indirectly in a utility earning an excessive rate of return. To the extent that a utility is able to achieve the targeted rate reduction and still recover all of its non-mitigatable stranded costs such that it achieves what we determine to be an excessive rate of return, this would suggest to us that greater savings were reasonably achievable, and the level of the MTC would have to be reconsidered.

H. Market Transition Charge

A specific market transition charge (MTC), which would be a separate non-bypassable component of customers' electric bill, must be established for each utility. This would provide the specific mechanism, consistent with the policies set forth above, to allow utilities the opportunity to recover stranded costs for a limited number of years. It is our judgment at this time, consistent with our intent for the transition to full competition to occur in a thoughtful, yet expeditious manner, that the MTC be limited in duration for a period of time ranging from 4-8 years from its implementation. However, we will entertain proposals for alternative MTC durations, which would be assessed as to the trade-offs offered between long and short-term benefits for consumers. It should be noted, in connection with securitization, that a separate surcharge with a duration different than the MTC may be established to provide the revenue backing for the ABS bonds. Moreover, we re-emphasize our earlier conclusion that non-mitigatable stranded costs associated with payments under previously-approved PURPA contracts with IPPs throughout their duration must be eligible for recovery, notwithstanding our targeted duration of the MTC of no more then 8 years.

The MTC would be established through a specific filing by each electric utility filed concurrent with its restructuring plan. Specific proposals for MTC composition, magnitude and duration would be provided by utilities, and reviewed in those proceedings. The MTC filing itself is discussed in more detail in the "Implementation" section at the end of this report.

For billing purposes, we would not rule out the imposition of a single MTC charge which would generate revenues for both securitization bonds and utility recovery of stranded costs. However, protections must be developed in that event to ensure that dedicated securitization revenues go specifically to their intended purpose: the debt service on securitized bonds.

I. Market Valuation

Obviously the most critical element to quantifying the stranded costs for a utility for purposes of establishing the MTC is ascertaining the market value of the utility's generation.

Some have argued that divestiture of generating assets by the utilities is the best and most precise mechanism for determining the market value of utility generating assets. In this manner, no estimates will have to be done. The proceeds from the sale of an asset will clearly indicate its perceived value in the generation market, and thereby reflect its actual market value. It is argued that this approach is clearly superior to estimating market value using some market price index or administrative estimate. Not only are generic market price indexes subject to volatility, they also may not reflect the long term value of the assets, which would be reflected in a sale of assets. Accordingly, a spot market index may understate the value of a generating asset, and thereby overstate the magnitude of stranded cost.

These arguments do have some merit. However, as articulated in the earlier section of this report addressing the "Generation" component of the "Initial Market Structure," there are a number of potential problems concerning a decision by the Board mandating divestiture of utility-owned generating assets. Accordingly, we are not prepared at this time to mandate that such action be taken. However, in their stranded cost filings, each utility will be required to propose a market valuation methodology and, moreover, we will direct that each utility in so doing address in their filings the extent to which their proposed methodology is subject to market volatility and provide appropriate sensitivity analysis, and to demonstrate that the methodology appropriately reflects the long term value of the asset, so that ratepayers are not exposed to inflated stranded cost estimates. We are particularly concerned that short-term market price indexes proposed to administratively determine stranded costs for purposes of setting the MTC may understate the true market value of a generating asset over its full life. We will determine at the conclusion of said filings whether divestiture is necessary to perform an appropriate market valuation.

VIII. Public Policy Issues

A. Introduction

Under the current industry structure the monopoly, vertically-integrated electric utility has the obligation, as previously discussed, to provide "bundled" electric service, which includes generation, transmission, distribution and customer services, to all customers. Electric utilities have also been relied upon to ensure universal access to electricity service, to be the provider of certain social programs, and to be an integral part of a societal safety net for those less fortunate consumers who are unable to pay their utility bills for reasons beyond their control. As well, monopoly utilities have been utilized as the vehicle for supporting the development and penetration of Demand Side Management programs and energy efficiency technologies (referred for these purposes as DSM).

As a result, these obligations and reliance on the utilities to perform these functions have become institutionalized. Numerous participants in this proceeding have commented on the need to protect, rather than abandon, public policy and social programs as the electric industry is restructured. As the transition to a competitive electric power industry unfolds, it is hoped and expected that many of these functions can and will be fulfilled by the marketplace. In addition, it is one of our intentions that lower utility rates will mean that there will be fewer consumers who are unable to pay their utility bills and in need of assistance. However, these changes will not occur overnight, and not all are assured. Accordingly, there is a legitimate concern that, at least during the initial transition to a competitive power market, certain public policy goals that have been traditionally fulfilled by electric utilities must be maintained, until it is shown that the marketplace can adequately provide these services. As such, we conclude that it is appropriate that, at least during the transition period, that existing utility institutions be relied upon to ensure that universal service is maintained, that cost-effective DSM continue to be supported, and that current social programs be continued. In so finding, however, we emphasize that electric utilities having these obligations imposed upon them should not be financially or competitively disadvantaged as a result.

B. Consumer Protection

In the current market structure, the Board has jurisdiction over all aspects of bundled utility service, including the pricing of that service, as well as the assurance of safe and adequate and proper production and delivery of power. Moreover, the Board has through both regulation and adopted policies a comprehensive framework of consumer protection guidelines and protections. Disputes concerning the rates being charged, bills being rendered, and the conduct of the utility's personnel in their interface with the customers, are adjudicated by the Board as part of its broad regulatory oversight of utility services.

In a restructured and unbundled industry, the Board would still have full jurisdiction over all aspects of distribution service, including customer complaints regarding rates charged for distribution and related service, bills charged for distribution and related service, and utility company personnel interfaces with customers, as well as pertaining to the construction and maintenance of distribution facilities such as substations, poles and wires. The same would hold true to the extent that customer services continue to be offered by the regulated distribution utilities, including such complaints as "fast meters."

However, the central theme of electric industry restructuring is to effectively eliminate the monopoly provision of electric power supply. Customers will be able to tap into a competitive market and take power from the supplier of their choice. The benefits of this change have been discussed at length previously, and will not be repeated here. However, by their very nature and indeed by definition, services offered in a competitive marketplace are not subject to the same degree of regulation as service offered by a monopoly utility. Primarily, this means that in a competitive marketplace, the price of that service is no longer regulated. Suppliers may seek to charge whatever price they deem appropriate.

However, the customer's ability to choose whatever supplier they wish imposes effective "market constraints" on the prices which suppliers can charge.

There has been concern expressed in this proceeding by many interests, particularly those representing consumers, that existing consumer protections explicitly or implicitly provided in a fully regulated environment, will fall by the wayside in a competitive environment. In turn, this has led to a discussion regarding the appropriate degree of regulation that the State should impose on non-utility energy suppliers.

What is clear is that in a competitive marketplace, there will no longer be a need to regulate the price for power. Indeed, even the prospect of price regulation would, we believe, hinder the development of a functional marketplace. However, there are legitimate issues with respect to the need for mechanisms to protect customers against fraud or other inappropriate behavior on the part of power suppliers. Moreover, while price will no longer be regulated as we move to a competitive market, there will still be a need to provide a forum for resolving customer complaints regarding pricing, as with all other products and services provided in a competitive market.

It is also important, we believe, to emphasize the crucial nature of electricity to the health, well-being and safety of the State. As well, it cannot be forgotten that what is being proposed in this report is a fundamental change in an industry which has, certainly from the customer's perspective, remained relatively unchanged since its infancy going back nearly a century. Accordingly we believe that, at the very least during the transition period, additional customer protections beyond those typical of other non-regulated industries operating in the State are appropriate and necessary. At the same time, we do not wish to burden this burgeoning industry with excessive regulation, and thereby inflate the price of their services to New Jersey's consumers.

Accordingly, we proposed in the January 16, 1997 Draft Report the following consumer protections which, when and if approved, would require certain legislative and/or regulatory modifications:

* All electricity provider (this would include marketers, brokers and aggregators) proposing to provide retail power supply services to customers in a distribution company's service territory would have to be certified as an eligible Transporter on the distribution system, pursuant to certain eligibility criteria.

* Transporter eligibility criteria would include the following:

  - a signed agreement to maintain an office within the State for purpose of accepting service of process and handling customer complaints, and to submit to jurisdiction of the courts of New Jersey, and to be bound by the laws of the State;

  - provision of assurances of financial viability, including the provision of security or a letter of credit;

  - a signed agreement to abide by suppliers' standards of conduct, such specific standards to be adopted by the Board in consultation with the Division of Consumer Affairs and input from other interested parties;

* Transporter eligibility criteria must be uniformly applied to all suppliers, and certification must not be unreasonably denied by the Distribution company.

* Certification disputes, if not resolved informally among the parties (i.e. supplier and the Distribution company) would be adjudicated and resolved by the Board.

* Once certified, repeated failure by a supplier to meet standards of conduct would be grounds for removal of certification, as determined by the Board.

* All certified Transporters must also be registered with the Board. Registration would encompass the filing of basic information pertaining to the supplier, such as name address, phone number and company background and profile. In addition, any company marketing so-called "green power" (that is, offering for sale electric supply with an environmentally friendly signature) would be required to include in the registration filing verification procedures regarding such claims. Specific registration requirements would be developed by the Board, in consultation with the Division of Consumer Affairs.

In response to the Draft Report issued in January 1997 the Ratepayer Advocate proposed the formation of a Consumer Protection Board consisting of the BPU, the

Ratepayer Advocate, the Division of Consumer Affairs and a diverse range of industry stakeholders to draft a consumer protection and information plan of action and to develop a comprehensive legislative proposal.

In our judgement this is an excellent proposal; we conclude that, rather then adopting specific consumer protection standards at this time, a Consumer Protection Task Force ("Task Force") should be formed immediately, and we so direct. The Task Force Executive Committee will be comprised of the BPU, Ratepayer Advocate and Consumer Affairs. To assure productivity and efficiency, the Task Force will consist of no more than approximately 20 members, comprised of consumer and industry representatives, and the three members of the Executive Committee. The consumer and industry representatives will be selected by the Executive Committee. The Task Force will function in an advisory capacity to the Executive Committee, which will produce a final document, with specific proposals to the Governor and the Legislature based upon the advice of the Task Force, by November 30, 1997.

The overall mission of the Task Force will be to develop policy proposals for policy makers, regulators and lawmakers in the State which will lead to the development of adequate consumer protection standards and consumer education programs prior to the phase-in of retail competition in the state's electricity and natural gas markets. Toward this end the Task Force will meet overall consumer needs by addressing the following:

* Review existing consumer protection laws to determine where gaps may exist under current laws;

* Promote consumer education so as to minimize consumer confusion over the changes in electric utility business structure;

* Develop strategies to educate consumers about the benefits and pitfalls that may

be associated with the emerging competitive marketplace;

* Develop strategies to increase consumer understanding of potential market abuses and opportunities for consumer recourse; and

* Promote increased awareness of the respective roles of the utilities, energy providers, marketers, aggregators, local and state government officials in consumer education and protection.

We envision that the Task Force will develop a specific mission statement and will break into several subcommittees to study particular issues, including consumer protection, consumer education , and environmental disclosure.

C. Environmental Issues

Ground level or tropospheric ozone continues to be New Jersey's most serious air quality problem, and the state continues to be classified as a non-attainment area for ozone by the U.S. Environmental Protection Agency (USEPA). This means that New Jersey, along with a number of other Northeast states, does not presently meet national air quality standards for ozone. Ozone is not emitted directly into the atmosphere, but is formed by photochemical reactions between volatile organic compounds (VOCs) and oxides of nitrogen (NOx) in the presence of sunlight. The primary man-made sources of these ozone precursors are the evaporation of solvents and fuels, and the release of combustion by-products, including emissions from fossil-fueled power plants.

Because ozone does not result directly from smokestacks or tailpipes, the pollutant is subject to the downwind transport phenomenon, the movement of ozone precursors by the prevailing winds over significant distances. Often these precursor gases are emitted in one area, carried hundreds of miles from their origins, and form high ozone concentrations over very large regions. Preliminary environmental modeling analysis indicate that the air quality of the northeastern section of the country, including New Jersey, is significantly affected by atmospherically transported NOx emissions from power plants located in the midwest and southeast areas of the United States.

The USEPA estimates that current NOx emissions generated from electric power plants in the eastern half of the country are approximately three million tons during the summer ozone season. Based on scientific analysis, USEPA has indicated that it will be necessary to reduce these NOx emissions to below one million tons during the ozone season, to prevent violations of the existing ozone health standard in downwind areas, such as New Jersey.

Although progress has been made in improving air quality, it is important to recognize the magnitude of the air pollution problem that remains, and the difficulty that New Jersey faces in reaching the National Ambient Air Quality Standard (NAAQS) for ozone. The northeastern states of New Jersey, Massachusetts, New York, Connecticut, Rhode Island and Maine are in either moderate, serious or severe ozone non-attainment areas. Most of New Jersey is classified severe non-attainment. The current standard for ozone is 0.12 parts per million (ppm) daily maximum one hour concentration, not to be exceeded more than once per year averaged over three calendar years.

In response to mounting scientific evidence that exposure to ozone levels of half the existing federal standard of 0.12 ppm can cause health problems, USEPA has recently proposed revising the ozone health standard to 0.08 parts per million averaged over eight hours. New Jersey supports the adoption of the proposed revised standards for ozone and fine particolate matter. A final determination on a revision of the ozone standard is expected in July 1997. At the proposed standard, New Jersey would have exceeded the limit for ozone on 33 days in 1996, five and a half times as often as it did under the current standard. Regional reductions in ozone and ozone precursors, such as NOx, will be even more critical if the revised health standard is promulgated.

The Clean Air Act Amendments (CAAA) requires states to develop plans to attain the ozone air quality standard in severe non-attainment areas by the year 2005 (Philadelphia/Wilmington/Trenton Air Quality Control Region (AQCR)), and the year 2007 (New York City/Northern New Jersey/Long Island AQCR). If New Jersey fails to reach attainment of the federal standard by the mandated deadlines, it will be necessary to impose more stringent measures. These strategies, such as a requirement for offsets to any new emission sources in the State, would further burden the State's existing business, industry, and residents, and have a damaging impact on the State's ability to attract new business and promote economic development. In addition, increased regulatory action would economically disadvantage New Jersey, in contrast to states in attainment areas which are required to meet NOx emission standards that are substantially less restrictive than those required in New Jersey and other states in the northeast.

Recent federal initiatives to introduce competition in the energy generation industry, and to thereby reduce energy prices, could have an impact on the State's efforts to comply with the requirements of the CAAA. On April 24, 1996, the Federal Energy Regulatory Commission (FERC) adopted Order No. 888 to allow open access of transmission services currently provided by native utilities to all non-utility electricity generators. (A notice of proposed rule making (NOPR) was previously issued on March 29, 1995, In Promoting Wholesale Competition Through Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmission Utilities, 70 FERC P61,357.) The Order is a major step in promoting competitive bulk power markets and thereby encouraging lower electric rates, as described earlier in this report.

The bulk or wholesale power market consists of transactions by retail distributors of power, including public electric utilities, municipals and cooperatives, who purchase power and then resell and distribute the power to retail customers. The FERC determined that equal, non-discriminatory access to the transmission grid was the most essential element in the development of a successful and fully competitive wholesale power market.

Environmental analyses show that a disproportionate amount of NOx emissions is currently generated upwind of New Jersey and that open transmission access could encourage increased electrical generation at power plants in those regions, further exacerbating the ozone problems in New Jersey. The State maintains that safeguards are needed to ensure that open access accomplishes the economic benefits from competition without increases in pollution.

The State's position on the open access issue was expressed in a January 19, 1996 letter to FERC, signed by Governor Christine Todd Whitman.

Although the State of New Jersey strongly supports the overall objective of Order No. 888, to introduce competition in the wholesale power market and thereby reduce electric rates, the BPU, the New Jersey Department of Environmental Protection (DEP) the USEPA, and the U.S. Department of Energy, along with a number of other interested parties and agencies in other states, have raised concerns regarding a potential long-term, adverse environmental impact from open access.

The State asserts that electric power industry restructuring must implement environmental comparability standards. Open access to transmission will enable lower-cost electric generators to increase power production and sell electricity to customers throughout the country. Many of these low-cost electricity generators are older, coal-fired facilities subject to less stringent pollution control requirements. This will result in a substantial increase in emissions, transported into the northeast by the prevailing winds, resulting in continuing unhealthful air quality in the State and additional clean-up costs to reduce pollution for New Jersey sources. More onerous emission reduction strategies will likely be needed for the State to meet the mandates of the CAAA to provide clean air for all citizens of New Jersey.

Governor Whitman has taken a strong stand on this issue at the regional and national levels. On the other hand, it might not be appropriate to take unilateral action, such as a ban or the imposition of fees on power generated out of state. Such action might only serve to isolate New Jersey from the competitive electric market and deny our citizens and businesses the ability to achieve lower electric costs and, importantly, will not solve this regional problem.

To support the State's position, the BPU and the DEP filed comments on January 30, 1996, in response to the FERC's Environmental Impact Statement pertaining to its then-proposed open access rule, calling for federal environmental comparability standards. New Jersey maintains that the most efficient and effective approach for ensuring that a truly level, competitive playing field exists is for the federal government, particularly FERC and USEPA, to use their authority to establish comparability environmental standards.

In adopting its final open access rule, via Order 888, the FERC determined that the environmental impacts associated with the new rule were de minimus and, in any event, that the Commission did not have authority to undertake mitigation actions. The BPU and the DEP, by comments dated May 23, 1996, filed a motion with FERC for a rehearing of its rule, pertaining specifically to the Commission's failure to address the mitigation of NOx transport. (The Board also requested a rehearing of certain jurisdictional issues unrelated to the environmental issue).

The State pointed out that less stringent emissions standards in certain sections of the country have a two-fold effect on New Jersey: the state's air quality is degraded by out-of-state pollution, and the State's utilities are placed at a significant cost disadvantage. The State's ratepayers, in addition to suffering the physical ill effects of poor air quality, will also be economically disadvantaged.

New Jersey maintains that FERC's Environmental Impact Statement (EIS) understates the impact the rule will have on competition, and the attendant increased utilization of existing coal-fired facilities. The State also posits that the FERC has a vital and active role, in conjunction with the USEPA and the states, in facilitating the establishment of generic environmental "rules of the road" to ensure a level, competitive playing field in the bulk power market.

On March 4, 1997, the FERC issued Order 888-A, which addressed the Motions on Rehearing. Order 888-A denied a rehearing on the environmental issues raised in New Jersey's and other's comments and reaffirmed FERC's Final Environmental Impact Statement (FEIS), stating that FERC has satisfied its obligations under the National Environmental Policy Act (NEPA). FERC reiterated its position from the FEIS that the open access rulemaking is expected to slightly increase or slightly decrease total future Nox emissions, depending on whether competitive conditions in the electric power industry favor reliance on natural gas or coal for the generation of electricity.

Over the longer term, FERC found that the preferred approach for mitigating any adverse environmental consequences would be for the USEPA and the states to address the problem through regulatory authorities available under the Clean Air Act. Since the issuance of Order No. 888, the USEPA has concluded that the Rule is unlikely to have any immediate significant adverse environmental impact and concurred that the FERC's analysis is adequate under NEPA.

However, the position of the USEPA on the long-term environmental impacts from open access to transmission service is consistent with the concerns raised by New Jersey. The USEPA is concerned that the open access rule could lead to increases in air pollution that would negatively affect the public health and welfare and diminish environmental quality. The USEPA also agrees with New Jersey that the air pollution transport problem needs to be comprehensively addressed through coordinated federal and state actions implemented through Title I of the CAAA, and if necessary, further action by FERC.

To address the long-range transport of ozone and ozone precursors, including NOx, the USEPA is working with the states through the Ozone Transport Assessment Group (OTAG), which includes the thirty-seven eastern-most states, to reach consensus on eliminating transport as an obstacle to attainment of the ozone health standard. OTAG is expected to complete its technical work by June 1997 and to provide recommendations to the USEPA shortly thereafter.

New Jersey supports the ongoing collaboration among states in addressing the air transport issue, particularly the efforts of OTAG, as well as the work of the Ozone Transport Commission, comprised of the thirteen northeastern states and the District of Colombia.

The OTAG is a partnership among USEPA, the Environmental Council of the States (ECOS), a national organization of environmental commissioners with members from 50 states and territories, and various industry and environmental groups. The goal of the partnership is to assess long-range ozone transport over the eastern United States and develop a consensus agreement for a regional strategy for reducing ground-level ozone and its precursors. DEP Commissioner Robert C. Shinn, Jr. serves as Chair of the OTC, as well as Chair of the OTAG's Modeling and Assessment Subgroup.

In its amendments to the State Implementation Plan (SIP), filed with USEPA on December 31, 1996, the DEP committed to conduct a collaborative modeling demonstration and to work with regional organizations to identify any reduction necessary from upwind areas that are necessary to attain the ozone NAAQS throughout the region. This commitment was made in response to the USEPA's policy establishing an alternative attainment process for ozone, whereby states can commit to a two-phased approach. Phase II requires participation in a two-year regional consultative process, with other states in the eastern United States and with the USEPA, to identify and commit to additional emission reductions needed to attain the ozone standard. This process is being conducted through OTAG.

After the consensus-building process is completed, New Jersey will submit the modeling and attainment plan that will show attainment through national, regional and local controls. As outlined in the SIP amendments, if no consensus is reached within the required timeframe, New Jersey expects that immediately thereafter the USEPA will exercise its authority under Section 110 of the Clean Air Act to ensure that the necessary emission reductions are achieved.

One collaborative emissions reduction measure under consideration by OTAG, and endorsed by the USEPA, is an OTAG region-wide cap and trade program, similar to the NOx emissions trading program being developed for the smaller OTC region. The cap on emissions would ensure two objectives: it would provide an overall pollution reduction in the entire eastern part of the United States in the future, thereby lessening the transport problem; and it would reduce the cost inequity to produce energy between the regions, thereby mitigating the impact from open access of transmission services. The trading mechanism is a market strategy to reduce the associated costs of pollution reduction.

Finally, a federal cap and trade program for reducing oxides of sulfur (SOx) has been in effect for three years and has been deemed successful. As such, the State and EPA have expressed support for a cap and trade program and have proposed that NOx emissions be capped regionally at one million tons - a two-thirds reduction. The BPU will coordinate with the DEP in the implementation of any future region-wide trading strategy.

The USEPA has indicated that it will exercise its authority under Title I of the CAAA to support the completion of the OTAG collaborative process to reduce emissions. States in current ozone non-attainment areas, such as New Jersey, are under notice that they must meet their State Implementation Plans (SIPs) by mid-1997 and to demonstrate how they will meet the current ozone standard. It is expected that the USEPA will notify the upwind OTAG states that they also need to amend their SIPs and adopt measures to address their contribution to unhealthful air quality in downwind areas.

The USEPA published an Advanced Notice of Proposed Rulemaking (ANPR) on January 10, 1997 (62 FR 1420-1423) which calls for the SIPs of certain states to reduce regional transport of ozone. Specifically, the notice announces USEPA's intention to conduct to formal process for implementing the regional reductions in ozone precursors, such as Nox, that are necessary for areas in the eastern United States to reach attainment of the NAAQS. The ANPR also announced the Agency's intention to publish a Notice of Proposed Rulemaking in the March 1997 timeframe, with final action scheduled for summer 1997.

By letter dated April 16, 1997, the USEPA decided to condense the two-step proposal process into a single notice in summer, 1997, to take maximum advantage of OTAG's technical and policy work. The OTAG has determined that it will complete its work in June, 1997. The USEPA is hopefule that the work of OTAG will result in recommendations that the agency could consider in the forthcoming rulemaking.

The April 16th letter also states that it is USEPA's preliminary view that the OTAG analysis demonstrates that the following states in the OTAG region will need to make additional emission reductions in order to address significant ozone contributions to the other states: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Indiana, Illinois, Kentucky, Maine, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Vermont, Virginia, West Virginia, and Wisconsin.

For the remainder of the states in the OTAG region, the USEPA believes that the preliminary work of OTAG does not support the need for additional reductions. However, USEPA believes that it is necessary to evaluate additional information, as well as wait for final recommendations from OTAG, to determine if additional emission reductions will be needed from these states to address ozone transport.

If the states are unable to reach consensus in a timely manner, the USEPA has indicated that it is prepared to develop a NOx cap and trade program for the OTAG region. The USEPA believes that these OTAG and Clean Air Act processes should be designed to mitigate any shifts in NOx emissions that might occur as the open access transmission rule is implemented. If the OTAG and CAAA processes fail to mitigate pollution transport, the USEPA plans to call on other federal agencies, including FERC and the Department of Energy, to assist in solving the problem. New Jersey supports the USEPA in exercising its authority if states fail to adopt adequate measures to address the transport of emissions to downwind areas.

Many of the public comments, pertaining to the possible environmental impacts of electric power industry restructuring, support New Jersey's stated position. Beginning September 1995, through the public comment period ending August 1996, in response to the Order Initiating the Energy Master Plan Phase II Proceeding (In the Matter of the Energy Master Plan Phase II Proceeding to Investigate the Future Structure of the Electric Power Industry, Dkt. No. EX94120585Y, dated June 1, 1995), a number of members of the public commented specifically on emissions comparability and the need to ensure that mid-west and southeast producers do not have an unfair competitive advantage over east coast electric power producers.

Many respondents advocated regional initiatives to address the equity and pollution transport issues. As the Proceeding evolved, a number of respondents suggested that it did not appear feasible, at that time, to solve the emission comparability problem within the current state electric power industry restructuring proceeding. If the existing regional and federal attempts at addressing these issues fail, then state contingency action should be considered.

There was also a position expressed by a number of parties, particularly environmentalists, utility labor unions and PSE&G, that the implementation of retail choice in the electric market will further exacerbate the NOx transport problem. As a result, it has been argued that the state should precondition the implementation of retail competition to the adoption by the federal government of uniform environmental standards on all power plants, irrespective of state lines. Alternatively, it has been argued that taxes or fees should be levied on any power sold in New Jersey that is generated at power plants in states with less stringent environmental requirements.

Specifically, concerns were raised that, much as in the federal open access proceeding, sellers from out-of-state, lower-cost, dirty power plants will be provided access to retail customers in New Jersey. Accordingly, ratepayers in the state may indeed lower their electric bills, but at the cost of dirtier air, with an ultimately higher cost to the state. It also has been argued that the persistence of an unfair competitive disadvantage for in-state generators, due to a large disparity of environmental standards, could lead to the closing of New Jersey power plants, thereby eliminating jobs and affecting local property taxes.

To the extent that wholesale competition expands under FERC's Order 888, and surrounding states open their retail markets, there will likely be markets for the power generated from low-cost, dirty power plants located out-of-state. In such event, were we to keep New Jersey's retail electric markets closed to competition, the state's consumers would be denied the economic advantages associated with these supply sources, but the state would still be subjected to the associated emissions via the air transport phenomena.

The BPU believes that the combination of proposed federal USEPA and possible FERC actions, along with collaborative state efforts, particularly the efforts of OTAG, can effectively safeguard against the potential adverse environmental impacts resulting from open transmission access. In that regard, however, Congressional action may be needed to clarify the USEPA's ability to ensure a fair solution to pollution transport in lieu of a consensus. Because the BPU believes federal action is the most efficient and effective strategy to address the transport issue, we advocate giving the existing and proposed measures a reasonable opportunity to successfully mitigate any increases in emissions in downwind states.

A number of proposals have been offered during the comment period by which New Jersey could purportedly, on a unilateral basis, address these environmental issues in tandem with or in lieu of federal or regional action, and otherwise encourage or require the use of "clear" or "green" power by retail suppliers in the State. These comments include proposals to require power portfolio emissions disclosure or labeling or, more proscriptively, require that all supplier meet certain environmental standards on a portfolio basis in order to be certified to serve retail customers in the State.

We agree that, as part of the solution to environmental concerns in a competitive electric power market, it is desirable for consumers in New Jersey to have access to information regarding the environmental signature of potential suppliers' power portfolio. In this manner, consumers would be able to make an informed choice of whether to purchase power from a supplier which relies on "cleaner" generating sources. Were consumers to opt for such "green" power in large numbers, a powerful signal would be sent to the energy market.

Therefore, we endorse and will explore the development of a rating system to allow customers to compare the environmental impact of different suppliers. Energy providers could be required to identify sources of purchased energy, including emission rates and/or other information which may be necessary. Disclosure information would serve the public's right to know and would be subject to the registration filing verification procedures for those suppliers marketing "green power."

Moreover, such labeling would obviate the need to precisely define what is meant by "green" power, which has proven to be problematic; rather, power portfolios could be compared in relative terms. However, the environmental disclosure proposals put forth during the comment period did not provide important implementation details. Further work is required on the development of a disclosure protocol including: identifying the specific pollutants to be included in the environmental "label;" specifying how various emissions levels would be "graded" to allow consumers to understand the import of emission data; and, perhaps most importantly, outlining how environmental data provided by suppliers could be verified to protect against false claims by suppliers.

Recognizing the environmental concerns held by the vast number of consumers in this State, we believe that the labeling of "green power" would encourage the marketing of renewable energy. At this time, we recommend that the State monitor the energy market and the environmental impacts from electric restructuring and not mandate, at this time, a set percentage of renewable energy in each supplier's energy portfolio.

As indicated previously, we do not believe that implementation of unilateral actions by New Jersey to mitigate adverse environmental impacts caused by electric restructuring is an optimal, or even preferable approach for New Jersey ratepayers and citizens at this time. Such actions, if taken alone, could result in higher costs for New Jersey electric consumers and, perhaps even more significantly, have no impact on the transport of emissions from out-of-state plants into the State.

However, the BPU and the DEP will continue to monitor the progress of OTAG and USEPA in developing a regional solution to the environmental impacts from electric restructuring. In the event that there is no favorable action through either the OTAG process or through federal initiative on a timely basis, the State will propose a contingency plan.

The disclosure information, previously discussed, could also help form the basis for developing any contingency plan. The viability of a disclosure requirement and protocol will be investigated by a subcommittee of the Consumer Protection Task Force consisting of the BPU, the Ratepayer Advocate, the Division of Consumer Affairs and the DEP, as well as representatives of stakeholder groups. During the interim period prior to the implementation of retail competition in the State, the BPU and the DEP will assess any impact from the restructuring of the electric power industry by closely monitoring appropriate indicators which could affect New Jersey's air quality.

In addition, the BPU and the DEP will continue to monitor the actions of neighboring states, several of which are considering adopting generation portfolio standards, in addressing the equity and pollution transport issues. If, upon review, we believe federal action is unsuccessful in creating a level playing field, New Jersey might pursue, as part of its contingency plan, collaborative action with other northeastern states, on an individual basis, to address the current inequitable environmental and economic circumstances. Individual state strategies adopted in the region need not be based upon identical programs but, because the northeastern state will be part of a common regional power marketplace, should be compatible and pursued contemporaneous with the action of other states.

Among the options that could be considered is the development of Generation Portfolio Standards or Emission Portfolio Standards methods. These options could require electric generators or suppliers selling electricity in New Jersey, respectively, regardless of the location of the generating facility, to meet an overall emissions rate consistent with an emission performance standard. A number of significant implementation issues will require further study if these options are pursued, including establishment of specific standards, verifiability of emission rate, Interstate Commerce Clause compliance, and other existing technical hurdles. These issues will be analyzed within the next year so that, if found acceptable, one or more could become part of the development of the certification program that will be applicable to any generator, retailer, marketer, broker, or aggregator, or other entity selling electricity in New Jersey in the event that appropriate regional or federal action is not forthcoming by October 1998.

D. Universal Service: Basic Generation Service

For purposes of this Report, in a competitive power supply market structure, basic generation service can be broken down into two categories of customers:

1) service for any customer who has not notified the distribution company of an alternative supplier choice. This category can be further broken down into customers with competitive supply options presented who simply decline those offers (so-called "choose-not-to-choose" customers), and those customers who have been presented with no offers for supply by alternative suppliers;

2) service for any customer who is dropped by its alternative supplier for any reason, including non-payment.

There is general consensus among the commentors that as we move to a competitive power supply market, a supplier(s) of last resort is necessary to ensure that all retail consumers have access to power. There has been debate in this proceeding as to how universal service should be provided, and by whom. Some support the notion that the local utility company (i.e. the distribution company) should provide this function. Others assert that the opportunity to serve these customers should be provided to all supply market participants. This could be done through either a random assignment of basic generation customers to all market participants, or through a competitive bidding process to select a specific basic generation provider(s).

It is our conclusion that, in order to provide for as orderly a transition as possible, at least during an initial transition period, the local distribution utility should be assigned the responsibility of providing basic generation service. While we will undertake to promote an aggressive consumer education program as we prepare for retail competition in the State, customer choice with all its attendant benefits as discussed herein, can introduce added complexity to the consumer's life. It is our judgment that, at least until the transition has progressed and there is a greater comfort level, consumers ought to have the option of simply "choosing not to choose" and buying essentially "rebundled" electric service from the local utility.

We further emphasize that prices for basic generation service must not be discriminatory, and should therefore be identical for all customers within each rate class. Importantly, however, as provided below, basic generation service customers should nonetheless have access to market priced power and thereby benefit from restructuring like all other customers. Accordingly, basic generation service must be available to all electricity customers starting in October 1998. Moreover; the generation component of basic generation service rates should be based upon a pass-through of the cost incurred by the distribution company to purchase power (including electric energy and capacity) in the competitive bulk power market, and thereby be market-based. These power purchase costs would be recovered via an adjustment clause, similar to the current fuel clause, in order to ensure timely recovery by the utility of these costs incurred on behalf of basic generation service customers. It is envisioned that such purchases may well come from the voluntary power exchange discussed in the earlier section of this Report. However, we would encourage distribution companies to develop and propose market-based standard offers or power portfolios for sale to basic generation customers, including appropriate incentive mechanisms to encourage the pursuit of portfolios beneficial to customers, and to provide an opportunity for appropriate compensation for risk incurred in developing a portfolio not based solely on power exchange purchases.

In order to best protect against the potential exercise of vertical market power or practice of self dealing by the distribution company and its affiliated generation company to the detriment of customers, we deem it an appropriate long-term goal that sale of power directly from an affiliated generation company to the distribution company for the provision of basic generation service not be permitted. However, since it is not known at this time precisely which mechanism will develop for utilities to assure and procure sufficient capacity for basic generation service customers as described in the reliability section of this report, we cannot preclude utilities at this time from utilizing existing generating assets to provide such capacity. However, we will require strict protections to assure that customers pay only the market price for such capacity.

E. Social Programs

It has been argued by some participants in this proceeding, including certain utilities and business interests, that the funding of social programs is appropriately done through general taxation as determined by the Legislature, as opposed to utility/ratepayer-funded programs. The cost of these programs is regarded as one of the causes for New Jersey utility rates being uncompetitive versus other regions of the country. However, as discussed previously, numerous social programs or policies are vitally important to numerous residents, and have become ingrained in the fabric of the State's utility industry. These programs and policies include the following: the winter moratorium program, which prohibits shut-off of power to certain categories of disadvantaged customers for non-payment during winter months; the costs associated with serving "bad debt" customers; low income assistance and weatherization programs, and existing late payment and deposit policies which are generally more liberal than those practiced by companies in other, unregulated industries. These policies, which have been in place for many years, are an important part of the State's safety net for the less fortunate. There is a legitimate concern as we move to a competitive energy market in the State that these protections will erode.

In order to avoid unnecessary disruption of these services, it is an appropriate goal that as part of electric industry restructuring and the transition to competitive markets, the State should preserve the provision and funding of social programs currently provided for by the "bundled" electric utilities in the State. Moreover, this transition should not result in the elimination or diminution of such programs. We emphasize this proposed policy to mean that the eligibility criteria and standards for the existing social programs should be maintained; actual funding levels to implement these programs will likely fluctuate as they have in the past according to economic conditions, weather and other external factors. Moreover, we encourage coordination with other non-utility social programs, both public and private, to gain efficiencies and avoid administrative duplication.

On the other hand, mindful of the legitimate concern that regulated utility rates not be utilized as a hidden tax and thereby exacerbate the non-competitiveness of these rates in New Jersey, we do not believe that this restructuring proceeding is the appropriate forum to consider new utility-funded social programs. While we propose protecting existing programs, we concur with the view that any new social program initiatives identified should be considered and adopted, where deemed necessary and appropriate, through separate legislative or Board action.

F. Demand Side Management

The Board currently has regulations in place that set the policies under which the electric and gas utilities in the State are to offer a number of conservation, energy efficiency and load management programs, collectively referred to as demand side management (DSM) programs. Contrary to the strict command and control approach begun in the late 1970's, the Board's current DSM Incentive regulations provide various financial incentive mechanisms to encourage the utilities to fund and promote various cost-effective DSM programs (cost-effectiveness in this context is generally described as a comparison of the direct and indirect costs of the program to the value of energy and capacity savings, plus environmental benefits, derived from the installation of DSM

Others, including citizen's groups and environmentalists, argue that there are remaining market barriers to DSM and that, as a result, utilities must remain active in the promotion and implementation of DSM programs. It is argued that, absent the utilities continuing to play this role, the energy DSM industry in the State will diminish.

It has been and continues to be the case that energy efficiency is an integral part of the energy policy of the State. The efficient production, transmission, distribution and use of energy benefits the State in many ways, not the least of which is to provide opportunities for the State's residents and businesses to reduce their energy bills. Moreover, energy efficiency provides environmental benefits by reducing the combustion of fossil fuels. As well, an active energy efficiency marketplace in the State provides for economic development and employment opportunities.

On the other hand, it is a reality that, while benefiting direct recipients of services through lower energy bills or the receipt of valuable energy information, inclusion of utility DSM program costs in rates can put upward pressure on the rates paid by customers at large. Moreover, as we move away from the utility structure where the local utility is a monopoly supplier of electric power production, and towards a structure where customers are free to choose any supplier, the direct economic benefits of DSM to the general utility base is much less clear. For example, the current justification that DSM will reduce the need for the utility to build or purchase new generating capacity, and thereby reduce costs for all ratepayers, will no longer apply.

Accordingly, it is our vision that over time the distribution utilities will phase down from serving a primary role in funding and/or implementation of many forms and applications of energy efficiency, and load management. We envision an increasing reliance on market forces to provide the impetus for installation of energy efficiency measures at customer locations. This will include the offering of DSM services by ESCos as part of an ever broader array of energy services, including power supply, in a competitive marketplace. However, we remain concerned that there remain market barriers to the implementation of all cost-effective energy efficiency opportunities. Moreover, there likely are little if any private sector mechanisms in place to provide for the implementation of non cost-effective, yet socially beneficial DSM programs. These may include programs to assist low-income customers in reducing their energy bills. It is our concern specifically that were utility funding of DSM programs to immediately be terminated, the marketplace would not immediately be able to step in and fill the void. This could in turn have serious effects on the ESCo industry in the State, thereby undermining the State's reliance on DSM as an integral part of New Jersey's energy future.

As a result, it is our determination that budgets should not be slashed, as some have argued, in response to the coming changes in the industry, and that during the transition to a restructured industry, that DSM programs continue to be implemented by utilities, and funded through rates. Initially, that funding would continue at levels consistent with each utility's DSM Plans, as reviewed and approved pursuant to the existing DSM rules as codified in N.J.A.C. 14:12. In this regard, we note there are currently significant disparities in the relative funding and spending levels for DSM between the state's electric utilities. The current low level of DSM expenditures by certain electric utilities must be addressed, subject to ongoing concerns regarding overall rate impacts. For the longer term, in order to prepare for the transition to an increasing reliance on market forces, we will modify the existing DSM regulations to provide for a filing by each electric utility for review by the Board of a "comprehensive resource analysis." The purpose of this filing would be to determine the appropriate level of energy efficiency and renewable power programs that should be funded through the distribution company's rates, and to identify the specific programs to be implemented by each utility. This review would encompass a full range of considerations, including but not necessarily limited to an assessment of the existence of remaining market barriers for various technologies, cost/benefit and payback analysis, environmental impacts, customer benefits, social benefits and rate impacts. Given the transition to a fully competitive marketplace for the provision of energy supply, we no longer see the need for a formal Integrated Resource Planning (IRP) process, where decisions on the need for, and type of generation resources for the utility, in addition to the assessment of DSM, are made.

In order to better ascertain the most appropriate format and nature of the comprehensive resource analysis, for the purpose of developing modifications to the DSM regulations, we will form a DSM and Renewables Working Group to develop specific recommendations. This Working Group will, in addition to developing recommended changes to the DSM regulations, analyze and address the future role of the distribution utility in the DSM and renewable power marketplace. Specifically, we will ask the Working Group to assess whether DSM program funds collected through utility rates are better administered, and DSM service funded through rates better delivered, by some independent entity. We will form the DSM and Renewables Working Group, and direct that its report be completed within six months following the conclusion of the unbundling, stranded cost and restructuring proceedings.

IX. Implementation Steps and Schedule

There are a number of substantial procedural steps necessary in order to implement the recommended policies set forth in this report.

There will be three filings before the Board by each of the electric utilities in order to set the stage for the commencement of retail competition starting in October 1998. These filings, which will be described below, include 1) a rate unbundling petition; 2) a stranded cost petition; and 3) a restructuring plan. Having considered both the approach of separate proceedings for each electric utility on each of these filings as well as the approach of consolidating them, we conclude, given the interrelated nature of each of the filings, that it would be most efficient and productive to consolidate all three filings under one proceeding for each of the electric utilities.

On or about the date of the filings, we will issue a Procedural Order(s) which will set forth the specific timetables, procedures and venues for the review of the various filings and the conduct of the proceedings. While we will be consolidating the three filings by each utility into a single docketed matter for each utility, we may establish different schedules for the adjudication of individual issues. Moreover, as indicated within this Report, there are a number of issues which will be addressed by each utility in their initial filings which lend themselves to a generic review. These include:

*Standards for Fair Competition

*Affiliate Relationship Standards

*Analysis of Market Power

*Mechanics for the Phase-In of Customers Choice

It is our current expectation that these issues will be pulled out of the individual utility proceedings and reviewed generically.

We will solicit filings only from the electric utilities on July 15, 1997. Parties to the proceedings will have the ability and opportunity, under the procedural guidelines and timetables to be determined by the BPU, to present testimony supporting modifications or alternatives, to the filings.

We direct each electric utility in the State to formally submit to the Board, no later than July 15, 1997, formal filings as described below, and otherwise consistent with the determinations in this Report. It is our intent to complete our review of each filing, and render final decisions, by no later than October 1998, in order to meet our recommended date for the introduction of retail competition in New Jersey.

FILING 1A: Rate Unbundling

A prerequisite to the establishment of retail competition is an unbundling of the rate structures for the electric utilities.

The following guidelines are intended to provide the minimum filing requirements and framework for rate unbundling filings to be submitted to the Board for review and approval by the State's investor-owned public electric utilities.

Services listed below are meant as a guideline for developing a rate structure that can accommodate and be the precursor to a restructured electric power industry where end use electric customers will have the option of procuring electricity (energy and/or capacity) from other than the native utility company. This list is not intended to be all-inclusive or to necessarily foreclose the proposal of other unbundled or competitive services.

Timing & Process

Unbundling filings would be subject to the BPU's administrative procedures, including intervention, discovery, and public and evidentiary hearings. The filings may be accepted, rejected or modified by the BPU.

The unbundled rates approved as a result of this filing would be implemented for a utility concurrent with the date of introduction of retail competition in its service territory.

Rate Unbundling

The filing would, at a minimum, include a separate charge for customer, distribution, transmission, production and societal benefit services for each existing customer rate class.

The **production charge** would include all generation capital and operation and maintenance costs, related allocated overheads, fuel costs and power purchase costs.

The **customer charge** would be a flat monthly charge which reflects the capital and operating and maintenance cost, and an appropriate allocation of overheads, associated with metering, billing and account maintenance.

The **distribution charge** would be a unit (per Kwh and/or per kw) charge that reflects the capital and operating and maintenance cost associated with distribution facilities, and an appropriate allocation of overheads, required to provide distribution service to a customer. This charge would also reflect the rate recovery of regulatory assets.

The **transmission charge** would be a unit (per Kwh and/or kw) charge which reflects the capital and operating and maintenance cost associated with transmission facilities, and an appropriate allocation of overheads, required to provide transmission service to a customer. This charge could also reflect the rate recovery of regulatory assets.

The **societal benefits charge [(SBC)]** would be a per unit charge that separately collects the costs currently embedded in rates, associated with the current provision of DSM, gas plant remediation, nuclear decommissioning and societal programs including winter moratorium, "bad debt" customers, low income assistance and weatherization and existing late payment and deposit policies. To the extent that certain of these costs could not be readily identified and separated from the bundled cost of utility service, a utility may propose to keep such costs bundled within the distribution charge.

A utility or other party to the proceeding would be provided the opportunity to propose, subject to review and consideration by the Board during the proceeding, that some of these charges could be rebundled for billing purposes. Rate rebundling for billing purposes would be considered by the Board in order to avoid customer confusion or for other appropriate reasons.

To the extent not already done in current utility tariffs, a utility would also be required to propose separate charges for all competitive services (other than production services -- already addressed in the production charge) offered to customers.

A separate charge or charges would also be proposed for load balancing or similar reliability-related services being offered by the utility pursuant to its filed restructuring plan.

In addition to the charges identified above, provision would be made for an additional unbundled charge referred to here as a non-bypassable stranded cost or **market transition charge" (MTC)**. Such a charge would reflect that component of a utility's current production costs which is "above market," but nonetheless ultimately deemed recoverable in rates, consistent with the proposed findings and recommendations in section VII. of this report. The production component of unbundled rates would accordingly be adjusted such that it reflected the removal of such "above market" costs. Indeed once retail competition begins, the production charge would simply be the price for power agreed upon between the customer and the supplier or the market price charge by basic generation service by the utility.

To the extent that a utility has filed or is filing simultaneously a base rate case, for purposes of regulatory efficiency it is appropriate to merge the unbundling filing and the stranded cost filings with such base rate case.

Cost Allocation and Rate Design

There has been discussion in this proceeding regarding the possibility of "restructuring" rates within the context of a rate unbundling proceeding. For these purposes, rate restructuring is defined as a reallocation of existing cost responsibility and revenue recovery among and between customer classes to address perceived subsidizations built into the existing rate structure. We are quite concerned with rate restructuring. As articulated throughout this report, it is our principal aim in this entire undertaking, consistent with other important goals, to bring about relief for all customers in the State from the current high level of rates being paid. It is our conclusion that all classes of customers are in need of relief from the high cost of electricity in the State. Any attempt at rate restructuring could, we believe, by shifting existing cost responsibility, have the effect of actually increasing rates for certain groups of customers. Such a result is undesirable, to the say the least.

Accordingly, in these filings, it is our determination that each utility be required to file unbundled rates, based upon an embedded cost of service analysis, which would achieve complete revenue neutrality on a company-wide basis relative to existing rates and, inter-class and intra-class revenue neutrality vis-a-vis existing bundled rates. Such revenues neutrality is critical, we believe, because rate unbundling filings are not intended as base rate cases and, as such, there will be no opportunity afforded in these proceedings for a utility or other party to propose a change in the overall revenue requirements of the company[23]. Nor, as will be described below, is it our desire that these filings produce a shifting of cost responsibility between customers. In those instances where a full base rate case is filed and merged with the unbundling proceeding, a utility would be required to file new unbundled rates which result in a similar rate impact on all customer classes.

In its filing, each utility must disaggregate the current bundled rate for each rate class into its functionalized components; that is, by production, transmission, distribution and customer functions. Except as otherwise noted, the cost of service study utilized, consistent with BPU-approved cost allocation methodologies, in the last base rate case when current base rates were established, should be employed to functionally disaggregate current bundled rates. To the extent that transmission charges currently paid by the utility pursuant to FERC-approved transmission tariffs are different than those suggested by the cost of service study, the current FERC charges would supercede. Once rates were disaggregated as described, the next step for the utility is to remove from the appropriate functionalized charge the costs associated with societal benefits, for purposes of setting the SBC, and the costs associated with other services for which a separate charge is being proposed.

The utility will be further required to provide bill impact analyses for customers of various sizes within each rate class, to demonstrate that the bill paid under the proposed unbundled rates is the same as that currently paid under existing bundled rates. Note: These "revenue-neutral" unbundled rates are for reference purposes, to which the rate reductions required by Section VII, will subsequently be applied.

[23] The only possible exceptions to this being the application of a MTC which resulted in some alteration in the current recovery of generation costs or, as indicated, if the utility unbundling filing is merged with a base rate case proceeding.

A utility may also file alternative unbundled rates, supported by an embedded cost of service analysis, that propose a reallocation of inter-class or intra-class revenue recovery vis-a-vis existing bundled rates. Other parties to the proceeding will also have the opportunity to present evidence and argue that some particular service(s) within the existing utility rate structure is, based upon embedded cost of service analysis, the object of a cross-subsidy. However, the utility or other party making such proposals would have a substantial burden of proof to demonstrate that the current rate design as approved by the Board is not reasonable. Further, it would be a basic principle that the final unbundled rate design approved by the Board would not result in any shifting of inter-class or intra-class revenue responsibility relative to current rates for equivalent service unless the utility or other moving party demonstrates and the BPU so finds that:

1) existing rates reflect cross-subsidies which, if perpetuated, will adversely impact the functioning of competitive markets; and

2) any identified and proven cross-subsidies are not otherwise appropriate for public policy reasons.

Again, we emphasize in this regard our strong aversion to any reallocation of rates within an unbundling filing that would result in an increase in rates, relative to bundled rates, for any group of customers.

FILING 1B: Stranded Cost Filing

The portion of a utility's stranded costs determined to be appropriately recoverable from ratepayers must be the net of all reasonable transition cost mitigation efforts available to the utility. The recoverable portion of the utility's non-mitigatable stranded cost should be collected via a non-bypassable charge, which will be referred to here as a market transition charge. It is further proposed that this market transition charge be assessed on all end users connected with the power grid in that distribution utility's service territory, regardless of the voltage level at which the customer takes service from the grid.

Absent a divestiture of generating assets by the utilities, in order to assess currently the magnitude of potentially stranded cost, it is necessary to estimate the market value of utility production. As the market develops and matures over time, it is likely that the precision of stranded cost quantification will improve. The market transition charge should therefore be subject to true-up, to reflect the realized market value of utility production through the transition period, either via market sales of power or from asset divestiture.

There will need to be a formal filing by each utility to determine a specific initial level of the market transition charge, consistent with our conclusions in Section VII. of this report. In essence, this market transition charge would become one element of the unbundled rate structure of the local distribution company; essentially a sub-component of the unbundled production charge. It is anticipated that the market transition charge, once established and implemented, will be phased out over a period of 4 to 8 years. The precise initial level of the market transition charge, as well as duration and rapidity of the phase-out, should be proposed by each electric utility and ultimately established by the Board based upon the policy findings set forth in Section VII. of this report.

FILING 1C: RESTRUCTURING/SEPARATION PLANS

The utilities must file for BPU review and approval specific plans to implement retail competition, consistent with the findings in this report. Such filings would include, but not necessarily be limited to the following, consistent with the conclusions in this report:

a) plans to functionally unbundle generation operations from the transmission, distribution, customer and energy service operations to ensure against anti-competitive behavior and/or plans to voluntarily divest of generation assets; plans for the operational and cost treatment of nuclear generating facilities; a horizontal market power analysis, a review and the establishment of specific standards of conduct aimed at specific proposed competitive services;

b) the establishment of procedures for customers to choose their supplier of generation service, including the provision on a timely and non-discriminatory basis of customer load profiles to customers and/or suppliers, as well as marketer certification standards;

c) specific proposed requirements for special metering equipment which balance the need to avoid cross-subsidy and "leaning" on the system with the desire to avoid the creation of significant barriers to competition.

d) plans for the performance of billing services and necessary tracking of energy and power flows within the distribution system for purposes of settlement and balancing, as well as proposed charges related to such services;

e) plans for the provision of Basic Generation Service, including mechanisms for providing capacity to serve such customers, and mechanisms for determining on an ongoing basis the incremental costs associated with providing "universal service," for the ultimate purpose of assessing the societal benefits charge;

f) plans for assuring that competitive suppliers meet all NERC and other applicable reliability criteria and proposals to replace existing long-term planning techniques for assuring that there will be adequate generating capacity in the future; and

g) plans for implementing a phase-in of customer participation in retail choice over the prescribed period, and for assuring penetration of all customer segments in the competitive market during all phases of retail competition.

APPENDIX 1: Public Participation Process

The June 1, 1995 Order initiating this investigation requested public input on approximately 25 detailed questions pertaining to the introduction of further competition in both the wholesale, as well as retail power industry markets. The Energy Master Plan Industrial and Consumer Advisory Council, originally organized to provide guidance during the development of the Phase I Report, was re-activated by the Order to give guidance during the initial critical junctures of the investigative process. The Council members represented the State's electric utilities, independent power producers, consumer groups, business and industry trade groups, and environmental interests. The Director of the Division of Ratepayer Advocate was a key member of the Advisory Council.

To include a range of perspectives and to reach all parties who had indicated an interest in the issue of electric power industry restructuring, the June 1, 1995 Order was mailed to approximately 700 industry representatives, legislators, consumer and environmental groups, and individual members of the public. The mailing included all members of the twelve subcommittees that previously helped guide the development of the Phase I Report.

The Order specified that interested parties were required to file a written notice of intent to participate in the Phase II Proceeding by July 25, 1995. Fifty-eight individuals and representatives of corporate entities filed notice to participate and four filed a motion to intervene. To encourage a high degree of public input into the restructuring investigation, every effort was made to include other interested parties, despite the filing deadline, as public awareness increased.

On August 8, 1995 the BPU convened a conference of all interested parties to discuss procedural aspects of the Proceeding, and to define the roles of the Advisory Council and all other participants. Initially, participants were organized into eleven subcommittees: Demand-side Management; Power Marketers; Environmental Organizations; Electric

Utilities; Independent Power Producers; Municipal Utilities and Power Associations; Contractors; Commercial and Industrial Customers; Residential Customers; Gas Utilities; and other Interested Parties. These subcommittees were based on the public organizational structure that had evolved during Phase I policy development.

The June 1, 1995 Order had specified that all written comments, including responses to the questions raised in the Order, were to be filed with the BPU by September 15, 1995. Participants were encouraged to file collaborative joint comments through their respective subcommittees, as well as individually. Summaries of both the subcommittee and individual comments on the initial questions concerning the introduction of competition in the wholesale and retail markets are included in **Appendix 4**. It should be noted that as the investigation proceeded, positions evolved and in some cases, differ from the initial responses. Therefore, any reference to interested party positions should be placed in context and time sequence.

As comments were filed with the BPU, copies were also distributed to all other participants in the Proceeding to encourage an ongoing dialogue. In accordance with the Order, reply comments to the initial comments were filed with the BPU by October 20, 1995. As previously done in the initial filing, all participants received copies of the comments by all parties. Summaries of the reply comments are in **Appendix 4**.

An informal, yet more intensive analysis of the issues raised in the Order and the response filings resulted in a round table discussion meeting with all interested parties on November 28, 1995. As a result of the meeting, all willing participants were organized into four working groups: 1) Industry Competition Model; 2) Stranded Costs; 3) Regional Issues; and 4) Public Policy Issues. A number of the issues pertaining to the electric power industry restructuring cross-cut among several or all of the working groups, but the above four umbrella topic areas served to focus the investigation.

Each of the eleven subcommittees was asked to nominate representatives to serve on the four working groups. Twenty public members joined the Industry Competition Model Working Group; seventeen participated in the Stranded Costs Working Group; fourteen worked on the Regional Issues Working Group; and 16 enrolled in the Public Policy Working Group. The working groups met or teleconferenced weekly, more frequently as the discussion and analysis intensified, during the months of December 1995 through February 1996. The BPU Staff attended the meetings to listen to the various perspectives and serve as technical resources, but public members organized and chaired the meetings and provided administrative support to the process. All working group meetings were open to the public to allow the opportunity for additional input.

During the first two weeks of March 1996, each of the four working groups individually submitted to the BPU a comprehensive report replete with policy recommendations proposed for the electric power industry restructuring. The reports contain recommendations on a number of policies reached by consensus, as well as dissenting reports included by individual members of the working groups on the more complex, contentious issues. The "Phase II Proceeding Staff Status Report: Restructuring the Power Industry in New Jersey" (Status Report), accepted by the Board on May 23, 1996 and released for public comment, is based on the recommendations in the four public working group reports.

The purpose of the Status Report was to provide an historical and factual background and context for the ongoing restructuring investigation, as well as a summary of the four working group reports and other relevant developments at the state and federal level. Importantly, the Status Report reached interim conclusions regarding the transition to competitive electric power markets. The Status Report describes the areas for consensus reached among the interested parties, identifies areas for further study and discussion, and presents recommendations for the next stage of the public process.

The Staff Status Report recommended that the BPU continue its investigation of the outstanding issues pertinent to the electric power industry restructuring, with expanded opportunity for public input. As a result of the recommendations contained in the Status Report, the Board formally adopted a two-pronged approach to gathering additional information and completing its investigation: 1) ordering both formal public hearings and a concurrent public comment period for written testimony, and 2) ordering informal negotiating sessions to attempt to reach consensus on the issues with representatives of all identified stakeholder parties (Order Modifying Procedures and Accepting Status Report, May 23, 1996, Docket No. EX94120585Y).

In accordance with the May 23rd Order, the Status Report was distributed for public comment, and public hearings and legislative-type hearings were conducted to receive testimony. Public hearings were held on July 18, 1996, in Trenton; on July 30, 1996, in Atlantic City; and on August 7, 1996, in Newark.

Legislative-type hearings, which were interactive hearings to provide opportunity for appearances by witnesses representing entities that had filed an Intent to Participate or a Motion to Intervene "In the Matter of the Energy Master Plan Phase I Proceeding to Investigate the Future Structure of the Electric Power Industry" (Dkt. No. EX94120585Y, Order dated June 1, 1995), were held on August 7th and 8th in Newark. Pre-filed testimony in preparation for the legislative type hearings were submitted on or about July 26, 1996 **[See Appendix 4]**. Any post-hearing follow-up comments were to be filed with the BPU by August 16, 1996 **[See Appendix 4]**.

Notices of the hearings were published in the July 1, 1996 New Jersey Register, as well as in the July 3, 1996 editions of the Star Ledger (Newark), the Times (Trenton), the Bergen Record, the Atlantic City Press, and the Asbury Park Press. In addition, the notice was mailed to the attached service list of participants who had indicated either an interest in electric industry restructuring, had specifically requested to be placed on the mailing list, or had formally participated in earlier stages of the Proceeding **[Appendix 4]**.

Concurrent with the development of a formal public record, a negotiating team was formed, composed of representatives of identified stakeholder groups. On June 6, 1996, a letter was sent to all participants that had served as part of the four working groups, asking for nominations to a negotiating team to represent the stakeholders on policy issues. A meeting was held on June 18, 1996 to finalize the list of negotiating team members, to discuss procedures and rules of conduct, and to set a schedule of negotiating sessions.

Based on the nominations received from Proceeding participants, the negotiating team, kept to a manageable size to facilitate discussion, included one representative from each of the four electric utilities in New Jersey; three from consumer groups; one from environmental interests; one from energy service companies; three representatives from independent power producers; two from power marketers, three from industrial, business and commercial customers; one from independent contractors, one representative from labor in the electric industry; one from public power associations; and two representatives from local governments, both at the county and municipal levels. The Director of the Ratepayer Advocate was also a member of the negotiating team. The Director of Energy of the BPU chaired the meetings.

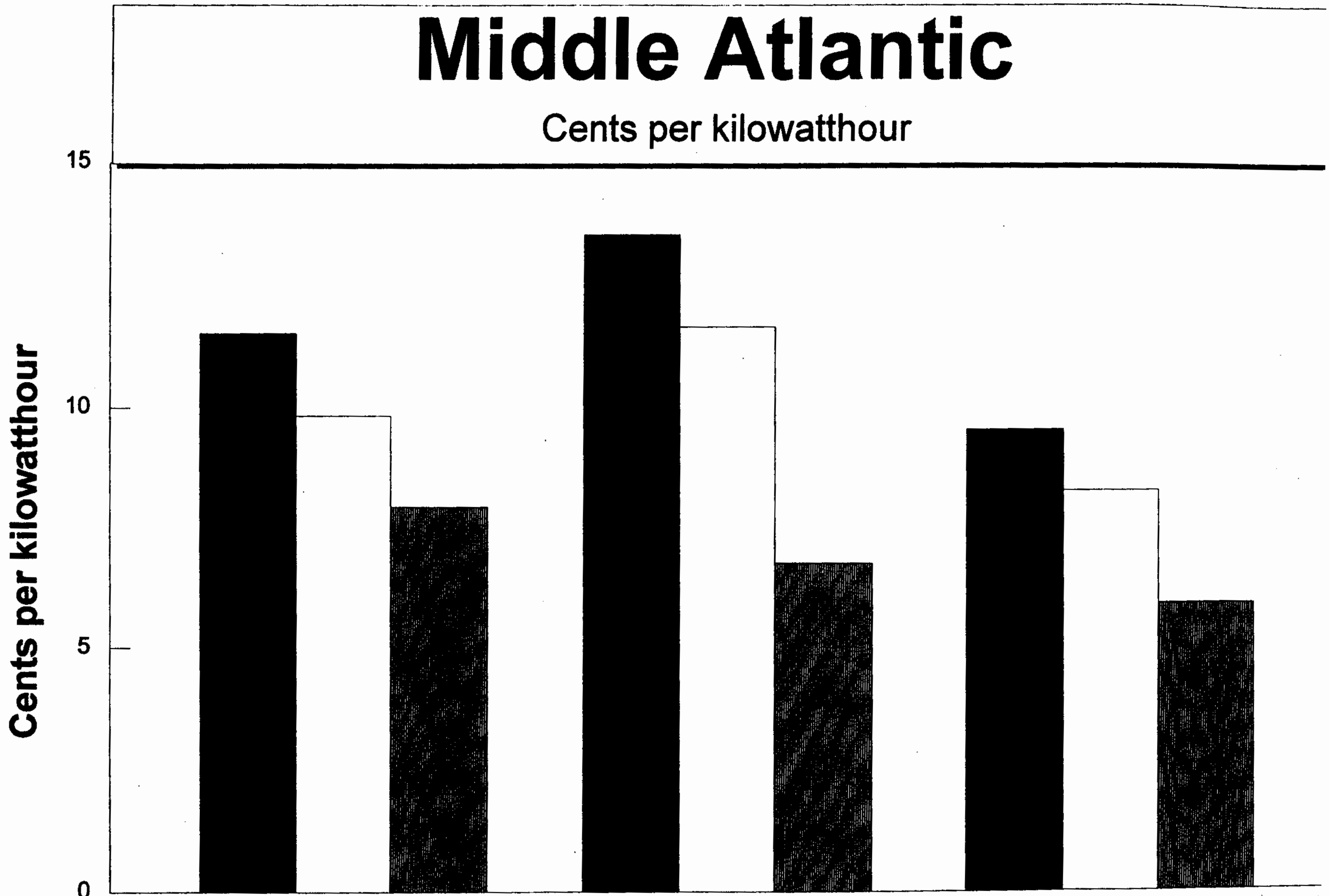
In addition to the negotiating team members, each stakeholder group was allowed one or two Technical Advisors to help provide technical assistance and to provide continuity if the negotiating team representative was absent. The negotiating sessions also included Technical Observers, who acted as additional technical resources, and represented New Jersey Gas companies, hydroelectric generation, and out-of-state energy generators.

Beginning with the outstanding issues raised in the four working group reports, the negotiating team discussed a comprehensive range of topics related to the benefits and downsides of various proposed industry models; the resolution of stranded costs; regional issues; and social/public policy issues. The discussion included the appropriate retail competition model and implementation timetable for New Jersey; analysis of the possible benefits from a pilot program versus a phase-in approach to retail competition; unbundling of tariffs; barriers or restrictions impeding the implementation of retail competition for all categories of customers; incentives for utility divestiture of generation facilities; and the functional or corporate unbundling of utility operations.

Other topics of discussion included the identification of and methodology for calculation of stranded costs; mitigation strategies for stranded costs; consumer protection standards; principles and procedures to promote and assure fair competition; parameters for the provision of basic service; state authority over out-of-state and non-utility energy providers; the appropriate funding mechanism to continue existing social and energy efficiency programs; how to ensure existing universal access; need for metering versus load profiles; technical issues related to metering, billing, balancing, and ISO infrastructure; reliability standards; competition transition charge; and verification of "Green Power" or environmentally good energy.

The negotiating sessions began June 27, 1996 and were held weekly until October 25, 1996. The representatives initially met in half-day sessions, but the discussions rapidly progressed to full-day meetings. The effort expended by the negotiating team, as well as the technical advisors, observers and subgroup members, was exceptionally dedicated. The input offered was an important supplement to the formal record of public comments submitted during the hearings and formal comment period. Although opinions differed during the discussions and no consensus was reached on the many aspects of electric industry restructuring, the negotiating team meetings provided an informal forum for a refinement of the many unresolved issues.

APPENDIX 2: Graphs Comparing New Jersey's Electric Rates With Other Regions In The Country.

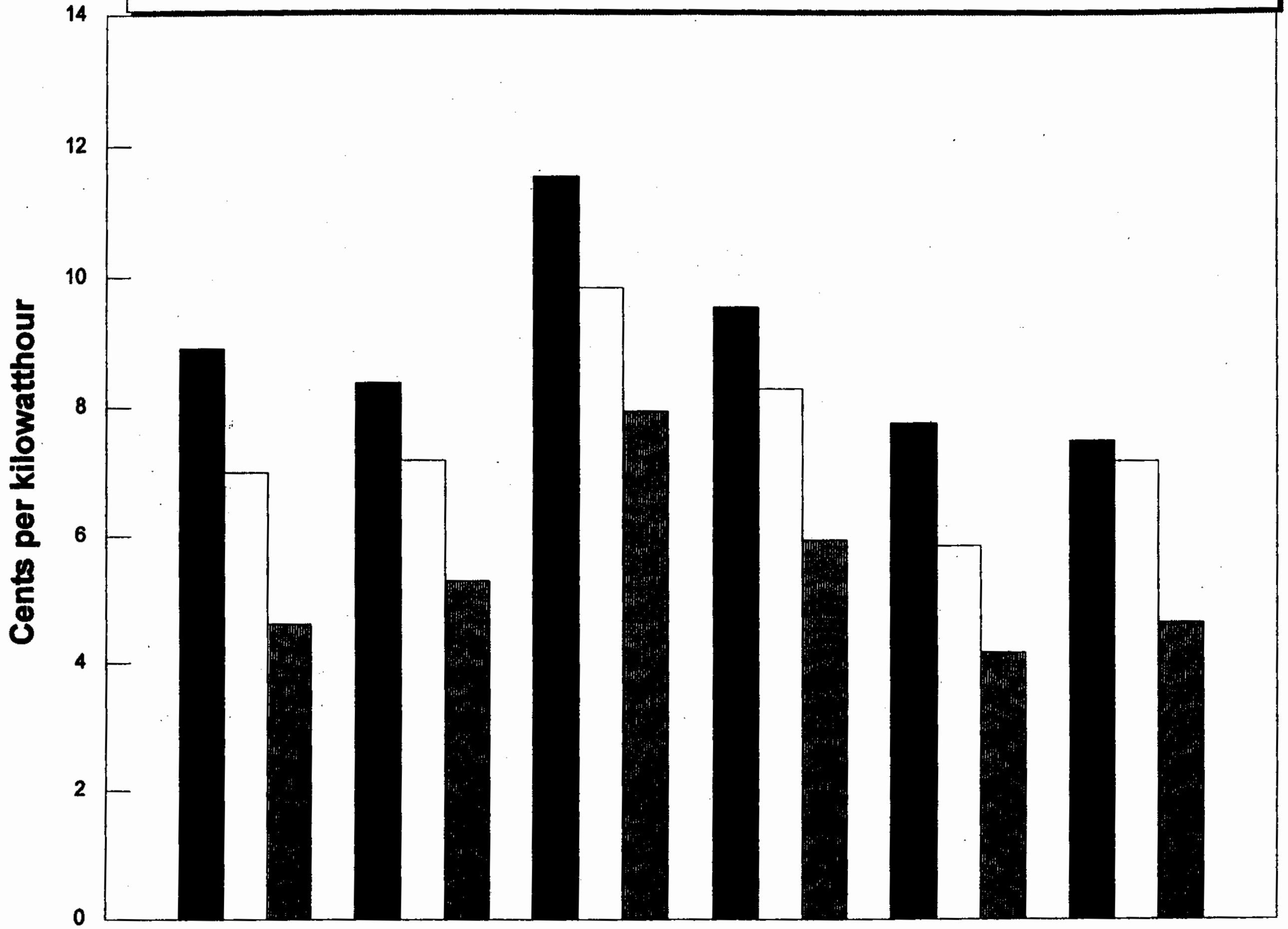


	New Jersey	New York	Pennsylvania
Residential	11.54	13.55	9.55
Commercial	9.84	11.67	8.28
Industrial	7.94	6.77	5.93

Source: Electric Sale and Revenue 1994 DOE/EIA-0540(94)

PJM States

Cents per kilowatthour

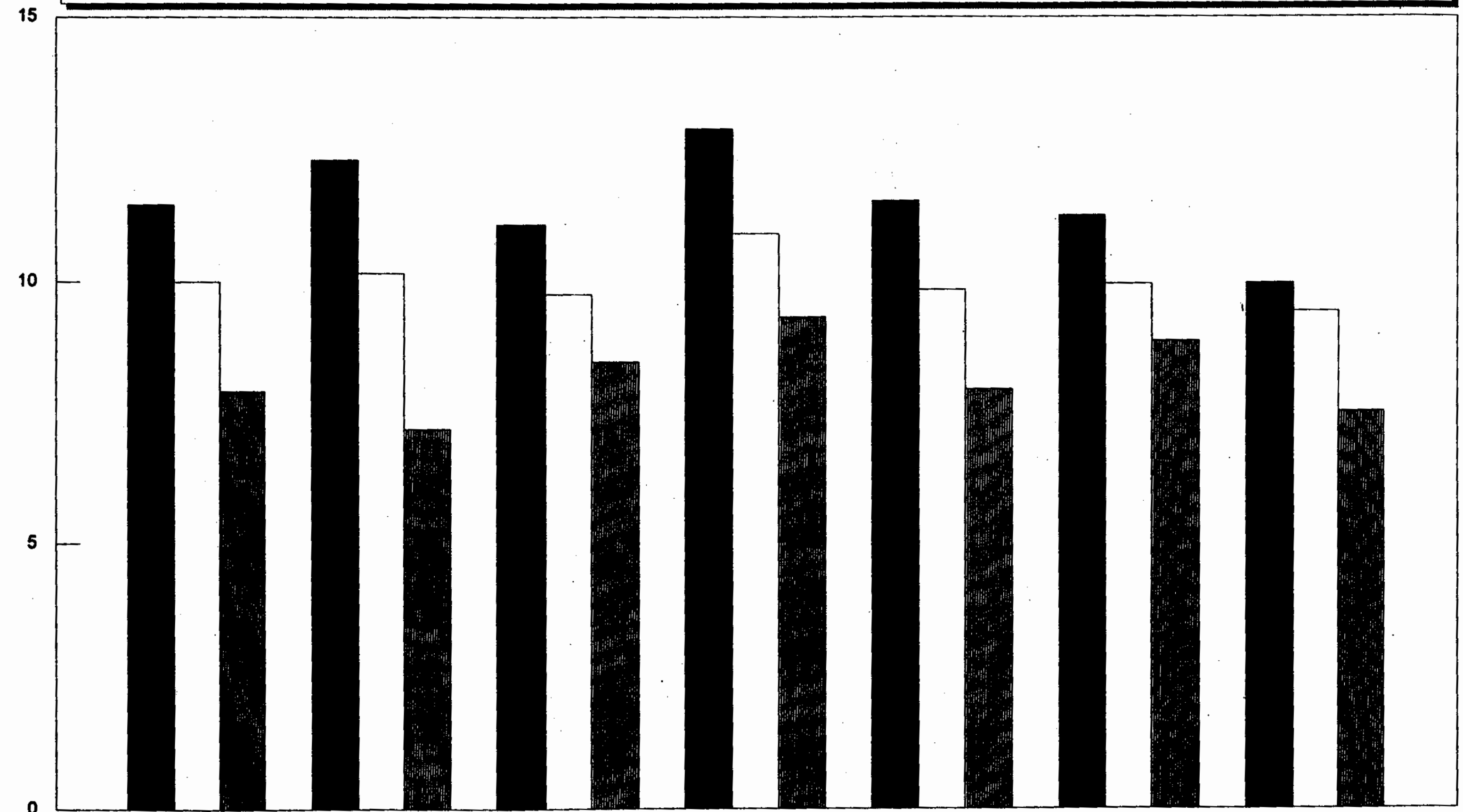


	Delaware	Maryland	New Jersey	Pennsylvania	Virginia	Wash. DC
Residential	8.91	8.39	11.54	9.55	7.75	7.47
Commercial	7	7.19	9.84	8.28	5.84	7.15
Industrial	4.62	5.3	7.94	5.93	4.16	4.63

Source: Electtric Sales and Revenue 1994 DOE/EIA 0540(94)

New England States

Cents per kilowatthour

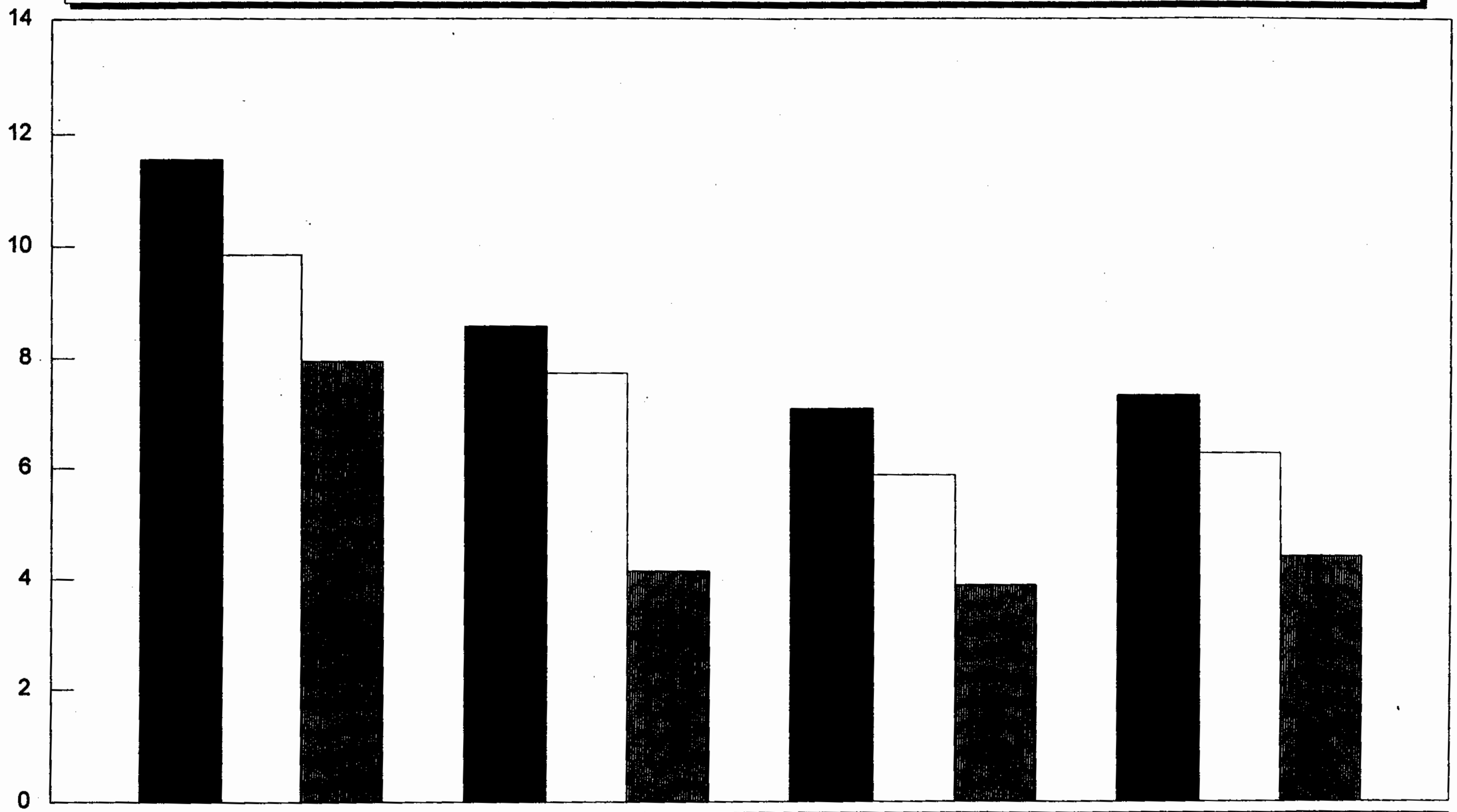


	Connecticut	Maine	Massachusetts	New Hampshire	New Jersey	Rhode Island	Vermont
Residential	11.47	12.32	11.09	12.91	11.54	11.26	9.96
Commercial	9.99	10.16	9.75	10.91	9.84	9.95	9.42
Industrial	7.9	7.18	8.46	9.32	7.94	8.86	7.5

Source: Electric Sales and Revenue 1994 DOE/EIA-0540(94)

East North Central

Cents per kilowatthour

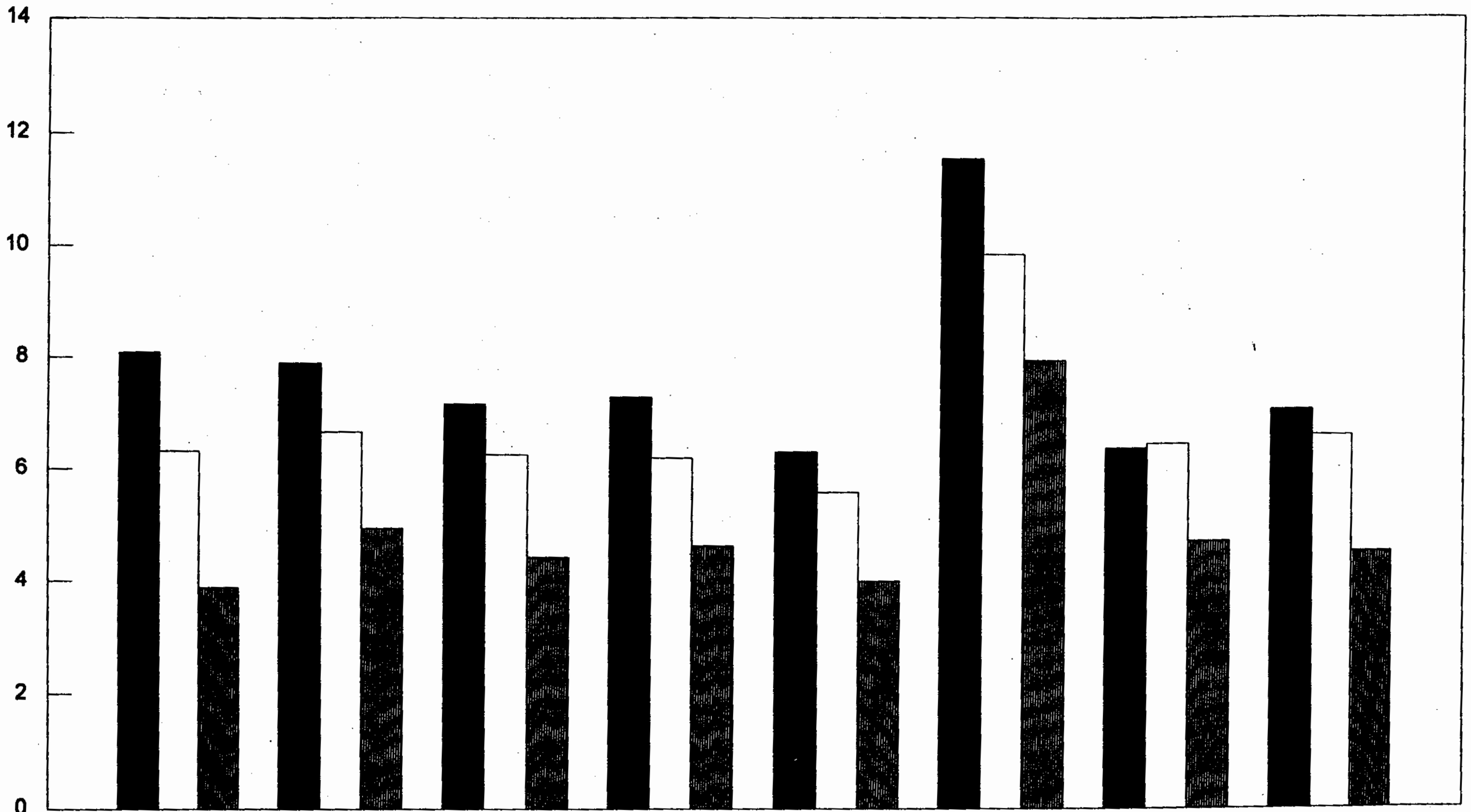


	New Jersey	Ohio	Wisconsin	West North Central
Residential	11.54	8.56	7.08	7.32
Commercial	9.84	7.72	5.87	6.26
Industrial	7.94	4.14	3.89	4.4

Source: Electric Sales and Revenue 1994 DOE/EIA-0540(94)

West North Central

Cents per kilowatthour

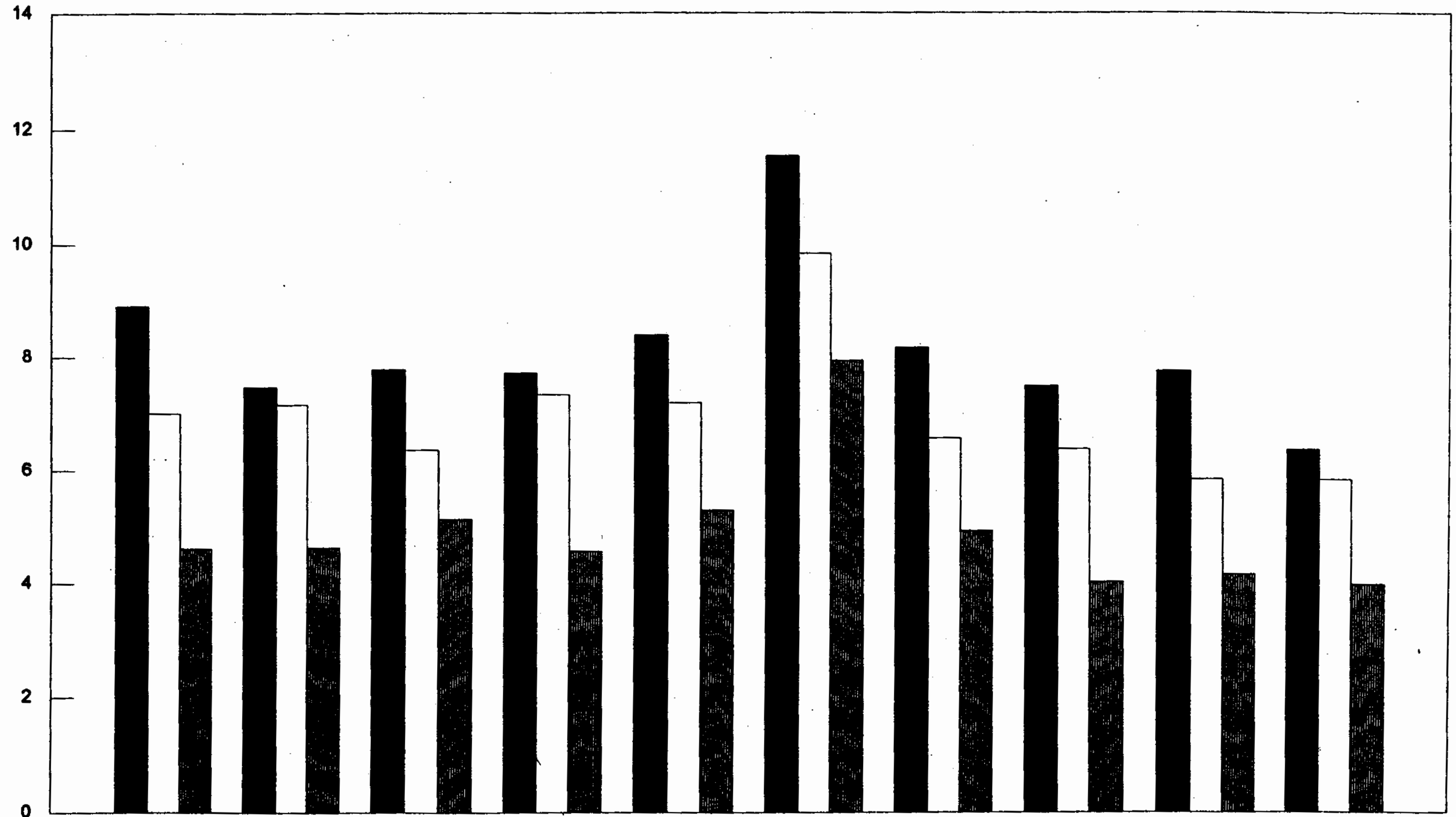


	Iowa	Kansas	Minnesota	Missouri	Nebraska	New Jersey	North Dakota	South Dakota
Residential	8.09	7.89	7.16	7.29	6.31	11.54	6.37	7.06
Commercial	6.32	6.66	6.25	6.2	5.58	9.84	6.45	6.6
Industrial	3.88	4.93	4.41	4.62	3.99	7.94	4.71	4.51

Source: Electric Sales and Revenue 1994 DOE/EIA-0540(94)

South Atlantic

Cents per kilowatthour

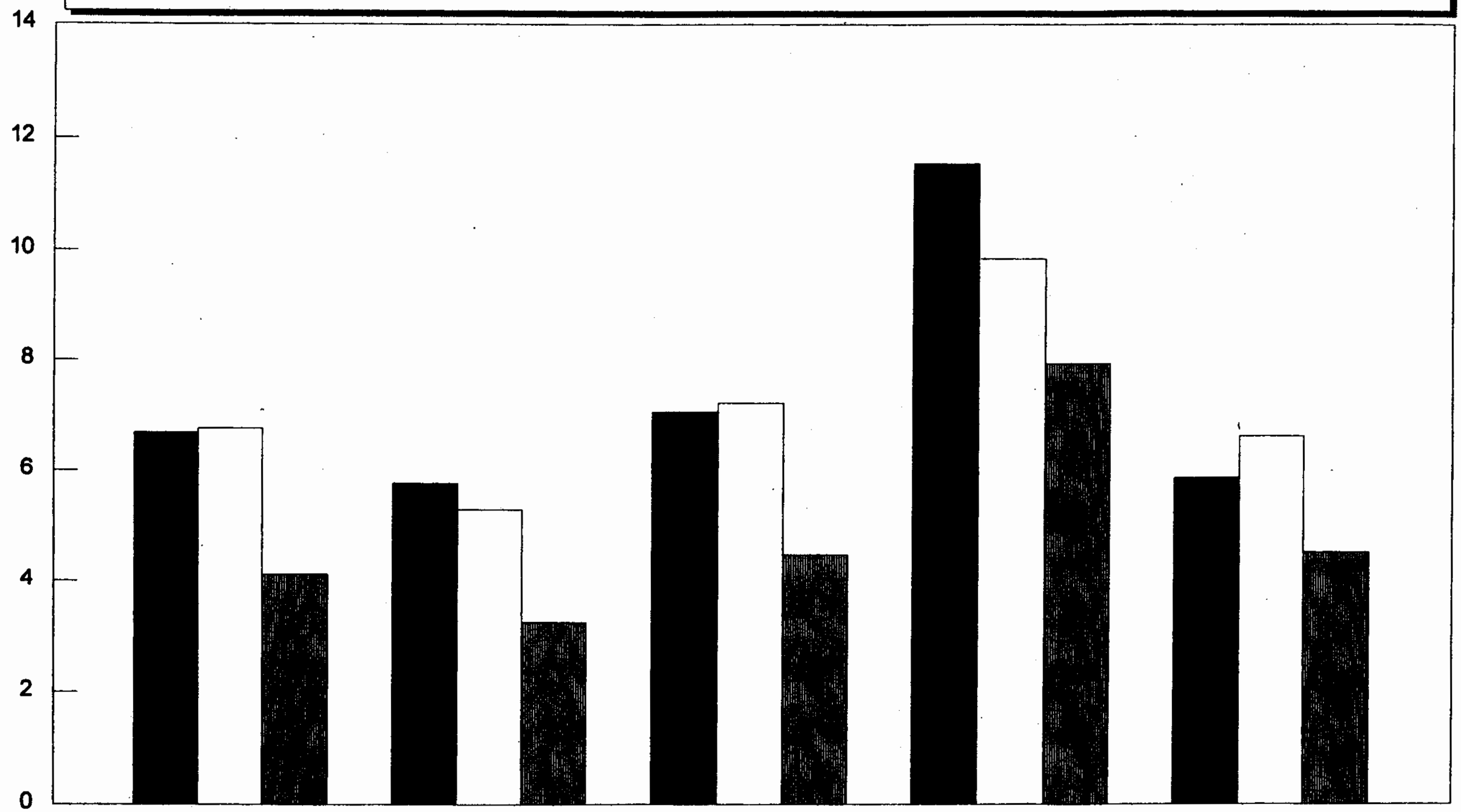


	Delaware	Wash. DC	Florida	Georgia	Maryland	New Jersey	North Carolina	South Carolina	Virginia	West Virginia
Residential	8.91	7.47	7.78	7.72	8.39	11.54	8.17	7.49	7.75	6.36
Commercial	7	7.15	6.35	7.33	7.19	9.84	6.56	6.37	5.84	5.83
Industrial	4.62	4.63	5.13	4.57	5.3	7.94	4.93	4.03	4.16	3.98

Source: Electric Sales and Revenue 1994 DOE/EIA-0590(94)

East South Central

Cents per kilowatthour

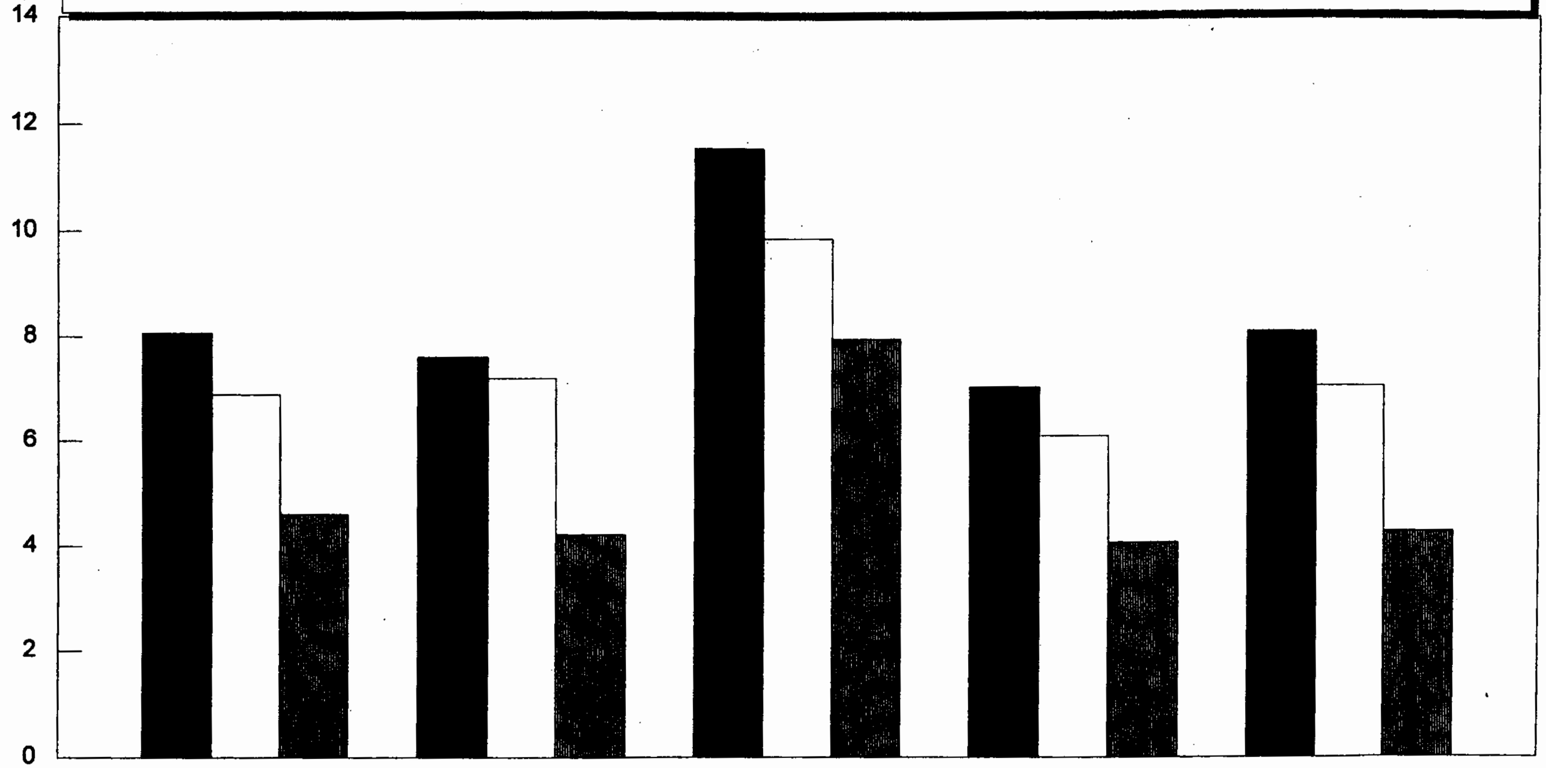


	Alabama	Kentucky	Mississippi	New Jersey	Tennessee
Residential	6.69	5.77	7.06	11.54	5.88
Commercial	6.76	5.29	7.22	9.84	6.63
Industrial	4.12	3.24	4.48	7.94	4.52

Source: Electric Sales and Revenue 1994 DOE/EIA-0540(94)

West South Central

Cents per kilowatthour

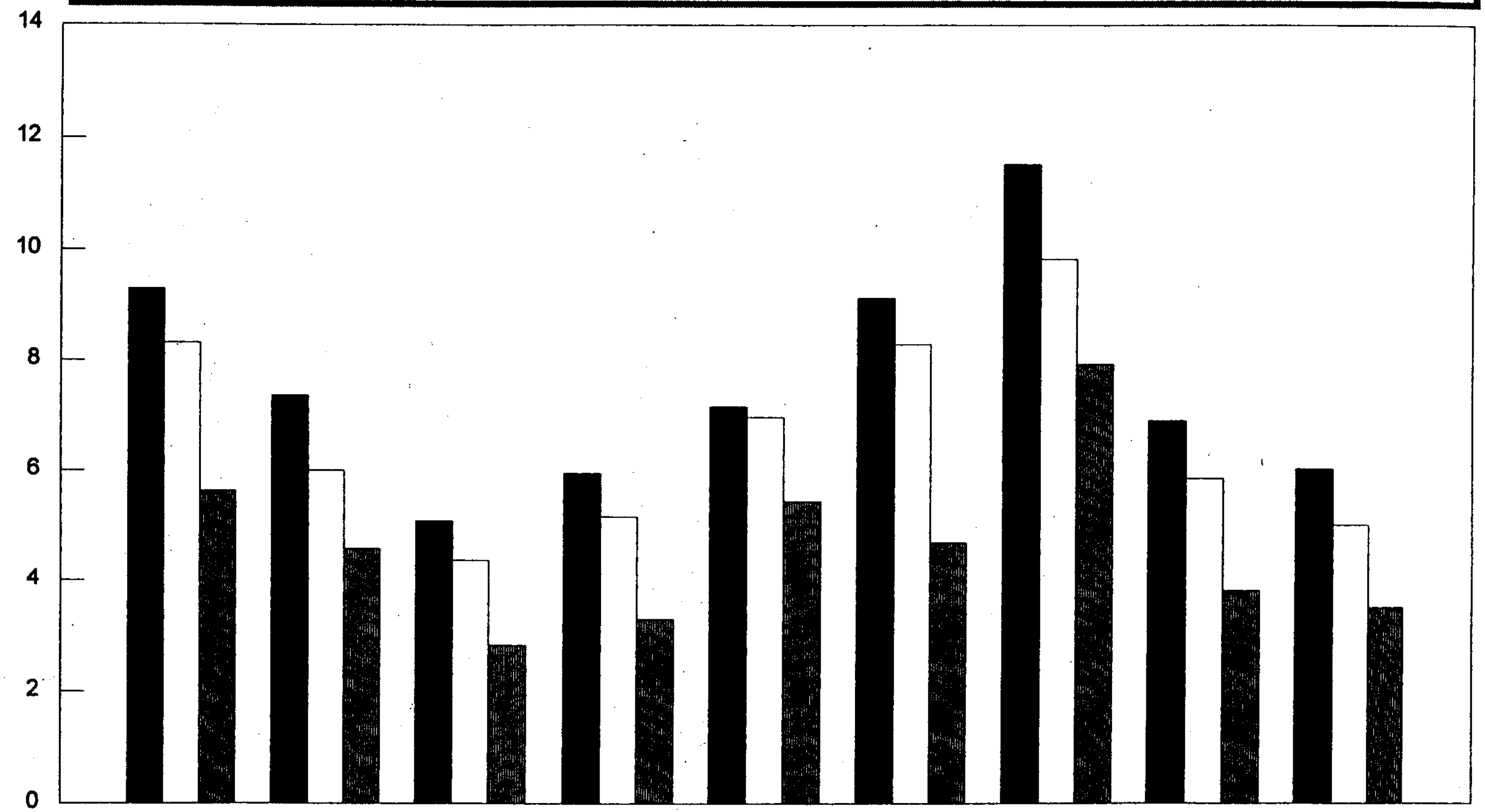


	Arkansas	Louisiana	New Jersey	Oklahoma	Texas
Residential	8.07	7.61	11.54	7.03	8.08
Commercial	6.88	7.2	9.84	6.09	7.04
Industrial	4.6	4.22	7.94	4.07	4.27

Source: Electric Sales and Revenue 1994 DOE/EIA-0540(94)

Mountain

Cents per kilowatthour

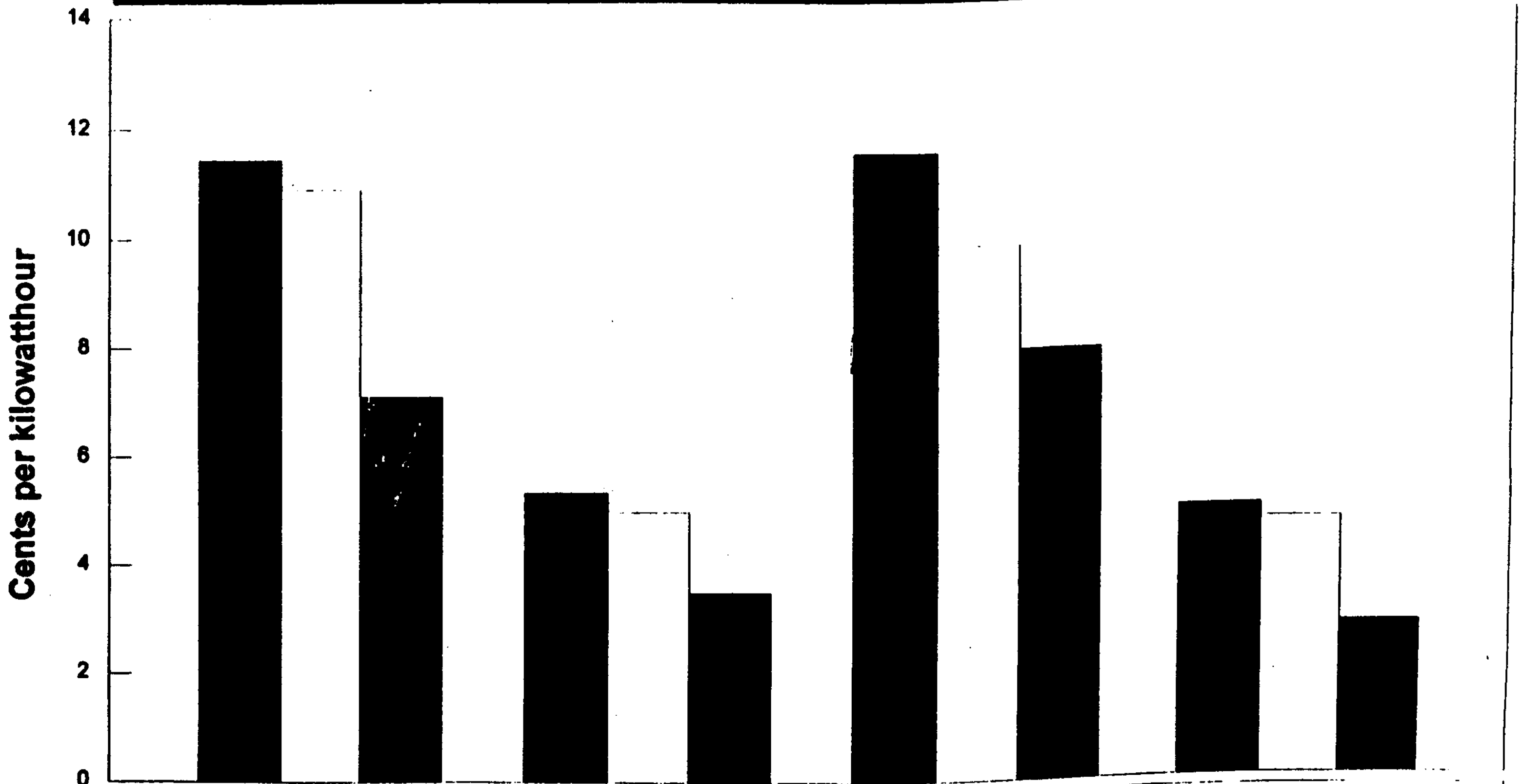


	Arizona	Colorado	Idaho	Montana	Nevada	New Mexico	New Jersey	Utah	Wyoming
Residential	9.3	7.36	5.09	5.96	7.16	9.14	11.54	6.91	6.04
Commercial	8.32	6	4.37	5.17	6.97	8.3	9.84	5.87	5.02
Industrial	5.63	4.58	2.82	3.3	5.45	4.7	7.94	3.83	3.51

Source: Electric Sales and Revenue 1994 DOE/EIA-0540(94)

Pacific Contiguous

Cents per kilowatthour



	California	Oregon	New Jersey	Washington
Residential	11.43	5.33	11.54	4.97
Commercial	10.9	4.97	9.84	4.72
Industrial	7.09	3.47	7.94	2.79

Source: Electric Sales and Revenue 1994 DOE/EIA-0540(94)

APPENDIX 3: FERC's ISO Principles From Order 888

1. The ISO's governance should be structured in a fair and non-discriminatory manner.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.

5. An ISO should have control over the operation of interconnected transmission facilities within its region.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission and consumption. An ISO or an RTG if which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

11. An ISO should establish an ADR process to resolve disputes in the first instance.

APPENDIX 4: Summaries of Written Comments and Participants

The following summaries of written comments have not been included with this report since they are voluminous in nature. Copies of this document can be obtained by contacting the Board of Public Utilities, Division of Energy at (609) 777-3317.

- Summaries of initial written comments submitted in response to the Board of Public Utilities Order Initiating Proceeding, dated June 1, 1995, In the Matter of The Energy Master Plan Phase II Proceeding To Investigate The Future Structure of The Electric Power Industry.

- Summaries of written reply comments submitted in response to initial comments submitted to the Board of Public Utilities' Order Initiating Proceeding, dated June 1, 1995, In the Matter of The Energy Master Plan Phase II Proceeding To Investigate The Future Structure of The Electric Power Industry.

- Summaries of written Pre-filed testimony submitted for the August 7th & 8th, 1996 legislative type hearings.

- Summaries of written post-legislative hearing follow-up comments filed with the BPU by August 16, 1996.

- Participants in the Energy Master Plan Phase II Proceeding

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Christine Todd Whitman, Governor

New Jersey Board of Public Utilities
Herbert H. Tate, President
Carmen J. Armenti, Commissioner

Division of Energy
Robert Chilton, Director

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