STATE OF NEW JERSEY

BEFORE THE BOARD OF PUBLIC UTILITIES

In the Matter of Public Service Electric and Gas Company to Transfer its Rights and Obligations Under Its Gas Supply and Capacity Contracts and Operating Agreements to an Unregulated Affiliate and for Other Relief	**Docket No. GM00080564**

DIRECT TESTIMONY OF

PAUL L. CHERNICK

ON BEHALF OF

THE DIVISION OF RATEPAYER ADVOCATE

Resource Insight, Inc.

JUNE 6, 2001

TABLE OF CONTENTS

SCHEDULES

I. Identification and Qualifications

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts 02139.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February, 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters. My work has considered, among other things, power supply planning, rate design, cost allocation, and utility industry restructuring. My resume is appended to this testimony as Schedule PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and seventy times on utility issues before various regulatory, legislative, and judicial bodies, including the

Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Vermont Public Service Board, Maine Public Utilities Commission, Rhode Island Public Utilities Commission, Connecticut Department of Public Utility Control, Texas Public Utilities Commission, New Mexico Public Service Commission, District of Columbia Public Service Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission, Public Utilities Commission of Ohio, South Carolina Public Service Commission, North Carolina Utilities Commission, Florida Public Service Commission, Pennsylvania Public Utilities Commission, New York Public Service Commission, Arizona Commerce Commission, New Orleans City Council, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. My resume includes a detailed list of my previous testimony.

Q: Have you testified previously before this Board?

A: I filed an affidavit in support of the Ratepayer Advocate's comments in Docket No. BPU EM00020106, on Atlantic Electric's fossil-plant sale.

II. Introduction and Summary

Q: What is the purpose of your testimony?

A: I discuss the proposal by Public Service Electric and Gas Company (Public Service or the Company), a combined electric and gas utility, to transfer its rights to all its pipeline transportation, supply and storage contracts to an unregulated affiliate ("Newco") under its holding company, Public Service Enterprise Group (PSEG). I focus on the following four aspects of the proposal's impact on the Board's ability to provide to ratepayers the goals of the Electric Discount and Energy Competition Act (EDECA):

- The effect of the proposal on market power in wholesale gas supply and in electric-generation services.
- The pricing of the proposed transfer, and whether it is likely to provide ratepayers with the best price and full compensation for the loss of these resources.
- The effect of the transfer on the reliability of gas supply for Public Service customers.
- The effect of the proposed transfer on the Board's flexibility and options in the design of Basic Gas Supply Service (BGSS) for Public Service's retail customers, as part of the Board's ongoing generic BGSS proceeding.

Q: What goals of EDECA might the proposed transfer imperil?

A: The Legislature stated its intent to, among other things,

- "Lower the current high cost of energy."
- "Improve the quality and choices of service."
- "Ensure universal access to affordable and reliable electric power and natural gas service."
- "Preserve the reliability of power supply…systems."
- "Authorize the Board of Public Utilities to permit competition in the… gas marketplace…, and thereby reduce the aggregate energy rates currently paid by all New Jersey consumers."
- "Provide the Board of Public Utilities with ongoing oversight and regulatory authority to…take such actions as it deems necessary and appropriate to restore a competitive marketplace in the event it determines that one or more suppliers are in a position to dominate the marketplace and charge anti-competitive or above-market prices."

The Public Service proposal could frustrate all these goals of EDECA.

Q: What are your conclusions?

A: I conclude that the proposed transfer could harm Public Service's consumers, and other consumers in New Jersey, in the following several:

- The proposal would be likely to concentrate control of gas-supply capability, especially to northern New Jersey and southern New York, allowing Newco to exercise market power, restrict supply, and profitably increase market prices paid by Public Service customers.
- The proposed transfer also threatens to produce market power in the electricity market, with PSEG affiliates controlling both a significant share of PJM generation and a significant share of the gas supply required by combined-cycle and other power plants, potentially allowing PSEG affiliates to manipulate market prices for electric energy.
- The transfer would ultimately leave Public Service's customers without any entity responsible for, and capable of, ensuring that reliable supply service can be maintained.
- The proposed transfer is not designed to provide maximum value to Public Service's gas ratepayers or to fully compensate them for their contribution to creating these supply resources or for the loss of those resources. As a result, total costs to Public Service's gas customers are likely to be greater with the transfer than without it.
- The transfer would restrict the Board's options for fulfilling its statutory obligation to design the BGSS framework and would result in loss of the Board's jurisdiction over gas-supply costs and rate design. It would also make it more difficult (if not impossible) for the Board to protect of Public Service's gas customers from high or volatile supply costs.

In addition, crucial aspects of Public Service's proposal remain ambiguous or contradictory, including the pricing of BGSS.

Q: Based on the record in this case, can the Board quantify the likely magnitude of the proposed transfer's effect on prices, competition, or reliability?

A: No. The Company has not gathered the basic data on demand, supply, and control of that supply in New Jersey, the mid-Atlantic, or the broader Northeast region. Public Service should not have proposed the transfer unless it was prepared to demonstrate that it would not increase market power or decrease reliability.

As recent events in California show, tight supplies of electric and gas capacity, market power by some suppliers, and a restructured supply market can result in enormous increases in prices, as well as seriously degraded reliability. The Board should not entertain any utility proposal to divest supply resources unless it can be assured that the divestiture will not adversely affect consumers.

Q: What are your recommendations to the Board?

A: Any consideration of transferring Public Service's contracts to any other entity should be deferred until the following conditions have been met:

- The Board determines how it wishes to structure BGSS service in the longer term, and how (if at all) Public Service's supply resources would be used to provide, support or stabilize that service.
- Public Service conducts studies of the effects of the proposed transfer on competition and market power in the New Jersey and regional markets for natural gas and electricity, and the Board determines that the

transfer will not harm competition or result in higher retail rates in either market.

- The Board establishes a mechanism to ensure that adequate capacity will be available to serve firm Public Service's gas customers, and determines that such mechanism is adequate to provide a high reliability of gas supply.
- The value of the resources is determined by an auction.

Q: How is the rest of your testimony structured?

A: The next section discusses the parallel between the problems in California and problems that could result from the proposed transfer. Although there are differences between California's electricity market and New Jersey's natural-gas market, the California experience illustrates the problems that can arise if deregulation is improperly structured.

Section IV considers, in turn, four major problems associated with Public Service's proposal: market power, the pricing of the transfer, reliability of gas supply, and the effect of the proposal on BGSS.

Section V discusses the implications of Public Service's updates to its original proposal in this proceeding, in the form of the Joint Position (and the schedules thereto) submitted by Public Service on April 16 2001, and the Addendum submitted by Public Service on May 21 2001.

III. Parallels with California

Q: Please briefly describe the origin of the problems in the electric and gas markets in California.

A: The problems started with legislative and regulatory moves to create a competitive market for electric-generation service. The California Public Utilities

Commission started its efforts to restructure the industry in the early 1990s. Following passage of restructuring legislation, the three major investor-owned California utilities sold off their in-state fossil and geothermal generation to non-utility-generation firms, in a series of sales in 1997 and 1998.

California, like much of the country, had a surplus of generation capacity in the early 1990s due to the construction of a number of non-utility generators, the economic slowdown, and a surplus of generation in neighboring regions. Projections by the California Energy Commission indicated that the surplus would continue through the decade. The utilities did not plan any new generation, since they were in the process of divesting much of their in-state generation. Non-utility generators did not start the siting process for many new plants due to the forecasted surplus and uncertainty over the extent of the incumbent utilities' control of the generation market. The utilities were allowed to retain their in-state nuclear and hydro plants, their out-of-state generation, and control of non-utility plants under contract with the utilities, as well as a much of the in-state fossil generation they voluntarily divested.

Each utility operated under a price cap, with a fixed amount of the rate dedicated to paying for spot market energy purchases to provide basic generation service and (with the difference between the fixed generation charge and the spot price) paying off the utility's stranded costs. To minimize the utilities' ability to manipulate the generation market, they were required to sell their remaining generation to the state Power Exchange and repurchase power for their BGS customers through the PX spot market. Customers who selected a third-party supplier were credited the spot price of energy.[1]

[1]The California market was structured without a capacity market.

In the first few years of the restructured generation market, the market seemed to function fairly well. Electric prices remained low, and the utilities were making good progress toward paying off their stranded costs. (San Diego Gas & Electric completed the recovery of its stranded costs, ending the rate freeze and putting all its BGS customers directly on spot-market prices.) Third-party suppliers picked up significant numbers of customers, with supplies that were greener, or perhaps slightly lower in price, than the utilities' spot supplies.

Starting in May 2000, the market changed dramatically, driven initially by market conditions and the lack of planning in the restructured markets:[2]

- A drought in the Northwest reduced hydroelectric supplies.
- Load growth in California and surrounding states further reduced reserves, putting upward pressure on electric prices.
- Expansion of generation capacity takes time and money, especially with the environmental constraints that apply in much of California. In the face of the previously low wholesale prices for electric energy, and uncertainties about the extent of market control by the incumbent utilities, new entrants were reluctant to commit funds to planning and licensing until need became clear. By that time it was too late to get new generation operating in time to forestall high prices and low reliability.
- Wellhead gas prices increased. Since gas fires the marginal generator in California most of the time, higher gas prices helped push up electric prices.

---

[2] I discuss some of these events in more detail below.

- In August 2000, an explosion on El Paso's main gas pipeline into California from the Southwest reduced gas supply, especially to Southern California, driving up gas prices.
- The effect of the El Paso constraint was exacerbated by the low level of in-state gas storage maintained by non-regulated generators and industrial customers.

The tight supply conditions were then exacerbated by the profit-maximizing behavior of suppliers with market power, as follows:

- According to the California Public Utilities Commission and Southern California Electric, an El Paso marketing affiliate that controlled much of the remaining El Paso capacity withheld gas supply, to push gas prices still higher.
- The California ISO has similarly concluded that the major owners of the divested generation withheld capacity, often by declaring it to be out of service, to drive up electric prices.[3]
- There are also indications that the generators may have withheld from the spot market low-cost gas they were purchasing under long-term contracts, putting it in storage at times of very high spot gas prices. By purchasing gas on the spot market, often from their own gas-marketing affiliates (and perhaps at inflated prices), the generators could justify higher electric prices and evade price caps. In the process, the generators may have driven up prices for both gas and electricity.[4]

---

[3]Forced-outage rates were reported to be much higher for the same units under competitive owners than they had been under utility ownership.

[4]See Wolak, Frank, and Robert Nordhaus. 2001. "Comments on Staff Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electricity Market." Market Surveillance Committee of the California ISO, March 22, 2001.

- The combination of the unanticipated increase in spot market prices and the price caps (which prevented recovery of the costs) pushed SCE and PG&E into financial distress (and PG&E into bankruptcy protection). When the state's largest utilities failed to pay their bills, smaller generators under contract to them were unable to purchase gas and shut down (and in some case filed for bankruptcy), other generators chose to sell their power out of state, and the Power Exchange shut down for lack of viable trading parties.
- The combination of restricted supply from the Northwest, higher load, and loss of generation due to the credit problems, apparently compounded by the withholding of generation by the large power suppliers, resulted in power shortages and rolling blackouts.

As a result of this multitude of problems, the market price of on-peak electric energy rose from roughly 2¢/kWh to more than 20¢/kWh. Spot wholesale gas prices in California, which until recently were lower than in the East, are now the highest in the country, often twice those in New Jersey. At times this winter, Los Angeles citygate prices for natural gas were over $40/MMBtu, when Phoenix citygate prices (at the other end of the El Paso constraint) were $8/MMBtu, and New York City prices were about $10/MMBtu.

California, having rushed into a complex and poorly planned restructuring system without adequate precautions, is now attempting to undo some of changes it instituted just a few years ago. The ability of the California Public Utilities Commission to fix these problems is extremely limited, since the essential resources are not longer under its jurisdiction, forcing the governor and legislature to take extraordinary measures. Since the utilities were prohibited from purchasing long-term contracts for power (and now lack the financial strength to do so), the State has stepped in to make those purchases.[5] The State has also set up an agency to build or buy power plants, pipelines, and transmission, to attempt to solve problems that the restructured utilities cannot or will not solve. Governor Gray Davis has threatened to confiscate the divested power plants if their costs cannot be otherwise controlled.

Q: Have the problems you described been limited to California?

A: No. While the scope of problems has been more severe in California (and in the rest of the Western Interconnection, heavily influenced by California) than elsewhere, some similar problems have been observed elsewhere.

- Utility resources that were sold off to third parties (such as GPU's fossil units) are now worth much more than the utilities received for them.
- Utilities are purchasing power for their customers from nonregulated suppliers at prices higher than expected when the utilities were restructured. This caused rate increases and accumulation of deferred balances in a number of states, including New Jersey, New York, Massachusetts, and Maine.
- In virtually all restructured electric markets, including New England, New York, and PJM, market-clearing energy prices have frequently been higher than can be explained by the marginal cost of producing energy, implying (or suggesting) the existence of market power.
- Despite the existence of the independent system operator (ISO) in each region, the threat of market abuse has been serious enough to require imposition of price caps on energy and/or capacity. The most comprehensive bid caps have been imposed on the three major owners of

[5] California has an existing state agency, the Department of Water Resources, which both generates and uses large amounts of power, which was able to assume this responsibility.

divested generation in New York City, where supply is more constrained than in the rest of the Northeast. In all three Northeastern pools, energy bids are capped at $1,000/MWh, and capacity prices are effectively capped by the option of paying fixed deficiency charges. These mitigation mechanisms, even combined with administrative review of anomalous prices, have not been fully effective in bringing energy prices down to competitive levels.

Q: Has Public Service proposed any comparable price controls for gas prices following the proposed transfer?

A: No. Other than the temporary and limited protection of the Requirements Contract, which would itself become increasingly dependent on market prices, Public Service has not proposed any price protections.

Q: How would the situation for Public Service's gas customers, after the proposed transfer, compare to the situation in which California electric customers currently find themselves?

A: There are many similarities, some of which would result immediately from the transfer, and others of which would be phased in over time. Indeed, in many ways, the post-transfer Public Service gas situation could be worse. Some of the similarities between the post-transfer Public Service gas situation and the current electric situation in California are as follows:

- Under the Public Service proposal, as in California, critical resources currently serving firm customers under regulated rates would be divested to unregulated entities.
- The available gas supply would be controlled primarily by Newco, and to some extent by an unknown number of major third-party suppliers, just as electric supply in California is dominated by a small number of

major generators. The situation for Public Service gas may be worse than for California electricity, due to the high percentage of supply that Newco is likely to hold, especially since Newco will control Public Service's local peaking resources and its rights to interrupt customers.

- The evidence in this record strongly suggests that New Jersey's gas supply would have little surplus in the face of large projected increases in demand. This is worse than the situation in California, which started the restructuring process with a surplus of capacity.
- The interaction between gas and electric supplies cause restrictions of gas supply driving up both gas and electric prices. Public Service already has an unregulated electric-generation affiliate that is an important player in the PJM region. The proposed restructuring would create an unregulated Company affiliate with similar strength in the interstate gas-delivery market. This concentration of unregulated gas and electric functions in a single holding company may produce even more serious interactions between gas and electric supply than those in California.
- Divestiture is likely to occur at less than eventual market prices. At least in California, there was some form of competition for the divested resources, resulting in some gains for ratepayers. Public Service proposes to transfer its resources at cost to an affiliate, without competition. This transfer is more likely to be below market value than are transfers structured like those in California.
- California did not have any central power-pooling arrangement prior to restructuring, and the new California ISO was weak compared to other ISOs. The situation would be even worse for gas in New Jersey, which is not covered by any central gas dispatching or pooling authority. Public Service has not proposed any form of central dispatch for the

restructured gas market, not even a weak one in the style of the California ISO.

- California's competitive electric market may have been impeded by the uncertainties in the market power of the incumbent utilities, which were allowed to retain control of a large portion of their generation. The control of a large portion of Public Service's gas supply by Newco could raise similar concerns.
- Under its proposed MPGS service, Public Service would no longer supply gas to its customers at regulated cost-of-service prices, and customers would be subject to the whims of the short-term market. In California, both Southern California Edison and PG&E continue to hold significant amounts of baseload capacity and contracts, at fixed or regulated prices, so not all of the supply for their customers has varied in price with the spot market.
- Under its proposal, Public Service would not be allowed to enter into long-term supply pricing contracts for its customers; all customers supplied by the utility would eventually be forced onto entirely market-priced supply. In California, the customers of San Diego Gas and Electric are paying for the high spot price of energy, flowing through the utility, while customers of the other two utilities were sheltered by rate freezes until the costs of market purchases drove the utilities into financial distress. After the completion of the proposed transfer and expiration of the transition contract, Public Service's customers would be in the same situation as those of San Diego Gas and Electric.
- Suppliers could divert supplies currently dedicated to firm Public Service customers to other markets, when that is more profitable.

- No entity would be responsible for ensuring adequate gas supplies to serve firm Public Service customers. The California electric system has an ISO, although its powers are limited. Public Service has not identified any entity that would have overall responsibility for reliability.
- Expansion of gas supply to serve northern New Jersey is likely to be time-consuming and expensive. Unlike California, where many developers could (and now are) adding electric capacity, relatively few companies are in a position to add pipeline capacity to Public Service's service territory.

The Company's proposal could also have a California-like impact on New Jersey's electricity supply, in that control of critical gas supply would be transferred to an unregulated affiliate of a price-regulated company.[6]

Q: Would Public Service's gas customers necessarily be subject to the same degree of price escalation as occurred in California?

A: No. No one knows what would happen with gas prices and supply in New Jersey if the transfer is permitted. However, some of the danger signs are present. Indeed, the warnings are clearer for New Jersey gas now than they were for the California electric system as recently as 1999. Even if New Jersey's constraints in gas supply and manipulation of gas prices are not as severe as those experienced in the California electric market, firm gas-supply customers could still experience significant price increases.

Q: How does the gas-supply system proposed by Public Service compare to the structure of the competitive PJM electricity market?

---

[6]In California, control of the gas supply was transferred to El Paso, which is an interstate pipeline rather than a local distribution company.

A: Public Service's proposal has many shortcomings compared to the PJM structure. The PJM ISO provides a number of services to ensure that the market works, including

- regional supply planning;
- coordination of maintenance;
- central dispatch;
- market clearing;
- establishment and enforcement of capacity requirements, including limits on the withdrawal of capacity and provisions for recall of capacity sold outside the region;
- monitoring of the market to detect and (where possible) correct market manipulation.

Public Service's proposal does not provide for any independent entity to provide any of these services.

Q: Does the existence of third-party suppliers provide protection against the type of problem experienced in California?

A: No. In the California, New England, and PJM electricity markets, third-party suppliers have dumped their customers and withdrawn from the market when prices rise and become unstable. This has been true even where the utility equivalent of BGSS has been market-priced.

Q: Briefly, what are the lessons of California for the Board's restructuring of natural gas supply in New Jersey?

A: The Board should be careful to avoid the perils of concentrated control of supply, leading to market power; of tight energy supplies controlled by unregulated firms; of inadequate supply-planning and procurement for retail customers; and of spot-market pricing of energy. Unfortunately, these are key features of the Public Service contract-transfer proposal.

Another lesson of California is the importance of being able to undo any radical changes in energy markets, if they produce unanticipated adverse consequences.

The Board should ensure that New Jersey will not need to take the same sort of desperate measures to regain control of gas costs and reliability.

IV. Effects of the Proposed Transfer

A. The Effect of the Transfer on Market Power

Q: What market-power problems could result from the proposed transfer?

A: The proposed transfer could create or exacerbate horizontal market-power problems in both the gas and electric wholesale markets.

Q: What do you mean by market power in this context?

A: I refer here to horizontal market power, in which a supplier with a significant portion of available supply finds it profitable to withhold capacity from the market in some situations, or to offer the supply at an artificially high price (which may have the same effect of keeping the supply off the market). The supplier sells less of its product (pipeline capacity, delivered gas at the citygate, or electric energy), but drives up the prices for its other sales.

The exploitation of market power raises market prices for all sales in the relevant markets, not just those of the party exercising its market power.

This strategic behavior is generally legal, so long as suppliers do not explicitly collude. Since anti-trust laws do not generally constrain horizontal market power, it is essential that rate regulators, such as the Board, avoid creating market power and also create mechanisms for limiting market power where it exists.

Q: What markets would the proposed transfer affect?

A: One of the problems in analyzing market power for a complex product like natural gas is that several markets are involved between the wellhead and the consumer's burner tip. The markets closer to the wellhead are called "upstream," while those closer to the end users are called "downstream." For example, Public Service's contracts include or subsume the following:

- Gas production, mostly the Gulf Coast and Alberta, Canada.
- Delivery of the gas from the wellhead to the pipelines in the producing areas.
- Transportation services on a variety of long-haul pipeline segments, and often on different pipelines, to bring the gas directly to the market area, particularly New Jersey. For example, Alberta gas is carried by Nova to the Trans-Canadian Pipeline to the Iroquois line into New York.
- Transportation services on a different but overlapping set of pipeline segments, from the Gulf producing areas to underground storage facilities in the Appalachian area (Ohio, western Pennsylvania, West Virginia).
- Transportation services on yet a third set of pipeline segments, from the storage areas to New Jersey.

Each of these categories represents one or more geographic markets. A firm may be able to exert market pressure in one of these markets, but not in others.

The major transportation corridors for gas in North America are illustrated in Schedule PLC-2. That map shows the constriction of gas-transportation capacity in New Jersey, compared to areas to the west.

Q: Is geography the only determinant of gas markets?

A: No. Another type of market segmentation occurs for different load levels, or seasons. In peak periods (traditionally the winter, although the use of gas for generation has created a secondary summer peak), the long-haul capacity from the producing areas is constrained, along with the withdrawal capacity in the storage fields and the pipelines from the storage fields to market. In the off-season, or more generally in mild weather, the lines to the storage fields, and the injection capacity at the storage fields, are heavily loaded, while the lines from storage to market and directly from the producing areas to market are less heavily used. A firm may be able to control prices only at peak periods, when supply is tight and when the firm has a large portion of the uncommitted capacity. Or its capacity may be fully committed at peak, but it may be able to control prices in shoulder periods.

Q: Does all capacity controlled by a firm contribute to that firm's market power?

A: No. Some capacity may be committed to serving a firm load, and therefore not be available to the market. For example, if Newco can withdraw 5% of its capacity from the market and increase prices 10% for its remaining capacity, exercise of market power would be profitable, since Newco's revenues would be increased by a factor of $1.1 \times 0.95 = 1.045$. But if 80% of Newco's capacity is being sold at committed prices (by tariff or contract), the 5% withdrawn capacity in that example would represent 25% of Newco's capacity sold at market prices, so its revenue on the market-based sales would be reduced by a factor of 1.1 × 0.75 = 82.5%.[7] On the other hand, if most other capacity is committed and supplies are tight, Newco's withdrawal of 5% of its capacity may create an even larger increase in market prices.

Market-power studies performed for FERC generally recognize the differences between total and uncommitted capacity, as well as locational considerations and differences in markets between peak and off-peak periods.

Q: How could the proposed transfer create or exacerbate market-power problems in the gas wholesale markets?

A: Newco is not likely to have any market power in the upstream markets. For example, Public Service's long-haul pipeline contracts provide roughly 1,500 billion Btu/day of capacity from the gulf producing areas, out of a total export capacity from those areas of some 30,000 BBtu/day to the north and east.

But closer to the market (that is, for capacity serving New Jersey and the mid-Atlantic generally), Newco could be an important player. The Energy Information Administration reports total capacity for transfers from the Midwest and Southeast to the Northeast is about 10,000 BBtu/day (see Schedule PLC-3). Public Service's share of that capacity appears to be somewhat more than 1,500 BBtu/day, since some of the transportation capacity from storage areas in the Midwest and South may be included in the capacity into the Northeast. Since EIA's definition of the Northeast includes

[7] Determining how much of Newco's sales would be at committed prices is complicated by the complexity and vagueness of Public Service's proposal. During the period of the Requirements Contract, Newco would have a large volume of committed sales through the BGSS, but PSEG has requested that Newco be given broad flexibility in pricing the BGSS. After December 31, 2003, the Joint Position states that both wellhead and delivery charges would be based on some sort of market pricing; at that point, Newco's incentives to drive up market prices would be essentially the same as if it were making all its sales into a short-term market.

Virginia and Pennsylvania, Public Service is likely to control more than 15% of transmission capacity from the south and west into New Jersey.

The basic problem is that Newco will have large amounts of pipeline and storage capacity providing service to northern New Jersey and such downstream areas as New York City and New England. Depending on how much of Newco's capacity is uncommitted and available for sales into the market, and the amount of other supply available in the market, Newco may control a significant share of the market and successfully exploit market power.

Q: Can control of 15% of capacity create the opportunity for exercising market power?

A: Yes. The three generation companies that have been accused of manipulating have the following shares of California capacity:

- 6% for Mirant, the former Southern Company generation affiliate;
- 4% for the Dynegy-NRG partnership;
- 7% for Reliant.

Even the total market share for these three firms is only 17%. According to Chuck Watson, the Chairman of Dynegy, the five major independent power suppliers account for only 25% of the state's generating capacity ("Dynegy's Watson defends Calif. suppliers, says per-MW profit same as two years ago." *Platt's Energy Trader* [May 24, 2001]: 1, 12).

Great havoc that has been attributed to the actions of suppliers who have 4–7% of the California electric supply. The prospect of an unregulated firm controlling 15% of the domestic gas supply to the Northeast (and probably a much larger share of supply to the New Jersey or New York metropolitan area) is thus a matter for concern.

Q: Could the market-power problem be exacerbated by other actions, beyond the control of the Board?

A: Yes. A subsequent merger of Public Service Enterprise Group or its successor with another holder of unregulated capacity rights in the Northeast could exacerbate the market-power problem. So could the eventual sale (or spin-off, followed by purchase) of Newco to another capacity holder.

Even without a merger, the emergence of other major unregulated capacity holders in the Northeast could make the market-power problem worse, if both Newco and the other unregulated suppliers manipulate prices upward to their mutual advantage.

Q: Has Public Service studied the potential for Newco to exercise market power?

A: No. As demonstrated by its responses to RAR-T-135–139, Public Service has not studied the concentration of control of pipeline or storage resources or of total or available capacity, or of Newco's ability to manipulate market prices. These responses are attached as Schedule PLC-4

Until those analyses have been conducted (preferably under Board supervision) and the Board is convinced that the transfer will not create market-power problems, no transfer should be allowed.

Q: Is there a surplus of pipeline and storage capacity, to provide a vigorous competitive market for gas transport to northern New Jersey and beyond?

A: No. Shell witness Rick Hornby, testifying in support of the Joint Position, describes the market in the following terms:

- "pipeline transportation and storage capacity" needed "to serve load" are currently "unavailable" (3, line 9).

- "Public Service currently controls the rights to most of the firm pipeline transportation and storage capacity available to serve this market." (3, lines 14–16).
- The marketplace is "capacity-constrained" (3, line 26).
- "The supply of firm pipeline transportation and storage capacity…is limited" (4, lines 14–15).
- "The market is not liquid" (4, lines 14–15).

On discovery, Mr. Hornby added additional information on the supply situation in the Public Service territory:

- "Firm Transportation service and storage capacity on [Transco and Tetco] is not available on a long-term basis because it is fully subscribed under long-term contracts." (RAR-Shell-1)
- No actual or potential third-party suppliers control any capacity at PSEG take points (RAR-Shell-2).
- "There is not a workably competitive market for firm supplies of delivered gas to the PSE&G service territory." (RAR-Shell-4).
- "it will be many years before there will be a competitive market in firm pipeline transportation and storage capacity." (RAR-Shell-8).

On cross, Mr. Hornby expanded on this theme, and testified that "there is just not a lot of surplus capacity available on a long-term basis" (Tr. 611) and "there's a need for more investment in pipeline infrastructure…. I don't know that there's a consensus as to how long it will take…before there might be competitive market in firm pipeline transportation" (Tr. 613).

This describes a market indicates ripe for the abuse of market power.

Mr. Hornby's description of the market is borne out by the data I have been able to find on the supply and demand for gas pipeline capacity to the Northeast.

According to "Status of Natural Gas Pipeline System Capacity Entering the 2000-2001 Heating Season" (*Natural Gas Monthly,* U.S. Energy Information Administration, October 2000, vii–xviii), the transmission capacity to the Northeast (which in this case is defined to include states as far south and west as Virginia, West Virginia, and Pennsylvania) was 77% utilized on the average day in 1999. That was a mild year prior to the boom in merchant gas-fired plant construction.[8] In peak periods, pipeline capacity would be more heavily utilized, and the growth in gas-fired generation (which uses as much or more gas in summer as in winter) will increase the number of days that pipeline capacity is fully used.

The EIA publication "The Northeast Heating Fuel Market: Assessment and Options" (SR/OIAF/2000-03, specifically Chapter 4, "Natural Gas Supply, Infrastructure, and Pricing", 38) notes

> Pipeline capacity in the New York City area appears inadequate to meet growing market demand, as indicated by recent price spikes in the area due to several constraint points that have developed in recent years. The Leidy area of north central Pennsylvania (a major hub area with numerous interconnections among major interstate natural gas pipelines) is rapidly becoming a potential constraint for pipeline gas flowing to the East Coast, and particularly for northern New Jersey and New York City.

Not all parts of the Northeast are equally constrained. EIA's presentation "Natural Gas Pipeline and Storage Deliverability" at the NARUC Winter Meeting, Washington, February 21–24, 1999 showed average demand on the pipelines serving New Jersey in the peak month of the 1997–98 winter to be over 95% (the highest category reported) of capacity.

---

[8]Interestingly, the capacity serving EIA's Western region (which is largely composed of California) was only 68% utilized on the average day in 1999.

The New England ISO recently issued a report that concluded that as early as winter 2003, “there is not sufficient operational flexibility to satisfy the coincident demands of both gas utilities and gas-fired generators…. Unless substantial new pipeline capacity and compression are added, material transportation deficits will occur in 2005—not just on the peak day, but also throughout the 60-day peak heating season.”[9] It is not clear whether the situation for Public Service would be better or worse than that in New England. Some supply constraints affecting New England may lie downstream of New Jersey and not directly affect the Public Service market. Nonetheless, the existence of adequate transmission from the middle Atlantic to New England does not necessarily imply that there is enough transmission from the South and Midwest to the middle Atlantic to meet the combined requirements of the Northeast.

Q: Did Public Service provide any evidence that there is a surplus of gas-transmission capacity to mitigate market power problems in New Jersey?

A: No. In response to a question about Mr. Hornby’s gloomy assessment of alternative sources of firm supply, the Company said that it does “not totally concur” with Mr. Hornby’s statements that “the marketplace is capacity-constrained” and “Public Service currently controls the rights to most of the firm pipeline transportation and storage capacity available to serve the market.” However, the Company was unable to provide any evidence to

---

[9] Levitan & Associates. 2001. “Steady-State Analysis of New England’s Interstate Pipeline Delivery Capability, 2001–2005. Holyoke, Mass.: ISO New England. The passage cited is from the forward to the report, a letter from Richard Levitan to ISO–New England’s system-planning director, Michael Henderson (2).

refute his assertions, and simply suggested that other unnamed LDCs "may or may not be in a surplus situation" (IR RAR-T-100).

Public Service did not list any particular sellers with excess capacity, or provide any information demonstrating that there was any aggregate surplus of supply to the region.

Q: Are there many parties that can add gas-transportation capacity to this area?

A: No. Unlike the electric-generation market, in which more than a dozen companies have proposed generation in New York, and more than thirty have proposed or built generation in New England, only four pipelines serve northern New Jersey: Transco, Tennessee, Columbia, and Texas Eastern.[10] A couple of others serve markets downstream from New Jersey (e.g., Iroquois to New York, Portland and Maritimes–Northeast to New England). Some of these would require addition of upstream capacity to increase their own throughput (e.g., Iroquois and Portland require capacity on Trans-Canada).

New pipelines can be built, but licensing and construction of major projects spanning several jurisdictions (US states and Canadian provinces) can take some time. New generation can be built in small increments (for example, with the combustion turbines of a combined-cycle plant added sequentially, followed by the steam generator), and capacity on existing pipelines can sometimes be increased by adding compression or looping a bottleneck. By contrast, it is more difficult to break down most major pipeline expansions into small, low-risk pieces. Most new pipeline projects must be built from end to end to be useful. In addition, timely FERC

[10] I have not found a compilation of generation-project proposals and sponsors for PJM, but several developers have announced plans for PJM, as well.

approval of pipeline expansion is often dependent on the pipeline securing commitments from shippers; in the restructured market, it is not clear who would make such long-term commitments, particularly on behalf of small retail customers. Thus, the market for merchant capacity additions may be more constrained for gas pipelines than for electric generation.

Q: Could the proposed transfer create any other market-power problems in the gas market?

A: Yes. Newco would control the dispatch of Public Service's local peak-shaving LNG and propane facilities (IR RAR-T-19). These resources are essential to the reliable and economic supply of gas to Public Service customers. Newco may be able to increase market prices and its profit by withholding peaking supplies, increasing market demand for Newco's services; by liquefying LNG at inappropriate times (again, increasing demand for pipeline services); or by drawing on Newco supply when peaking would have been economically justified.[11]

Avoiding this abuse would require further Board oversight of Public Service's dispatch, as well as the establishment of some contractual or regulatory mechanism to enable the Board to penalize Newco for abusing its

---

[11]Public Service originally proposed that the costs of the peaking resources would be borne by Public Service customers, even though Newco would control the resources, and that Newco would not be subject to prudence review. In the course of this proceeding, Public Service changed its position, asserting, "The Company will be compensated for the revenue requirements of the facilities now collected through a portion of the balancing charge." (RA-T-154, Tr. 461). The new Requirements Contract filed May 31 specifies that Newco will pay Public Service for the O&M and capital costs of the peaking plants (§2.4) and maintain the fuel inventory at those facilities at its own cost (§8.2). These arrangements do not prevent Newco from using the peaking resources to manipulate market prices, but only ensure that Newco will pay for any inefficiency in the dispatch of the peaking resources.

control of the peaking facilities, without imperiling the financial condition of Public Service.

Q: Other than the costs imposed by Newco's abuse of market power, could any other problems arise as a result of Newco's control of Public Service's peaking resources?

A: Yes. Newco may also find it economically beneficial to dispatch peaking supplies in ways that increase costs to Public Service customers, in addition to the effects of market power.[12] For example, if Newco has pipeline gas costing $4/MMBtu that it would normally sell to Public Service, but the market price is $6/MMBtu, Newco may decide to have Public Service operate its propane plants at $7/MMBtu. Newco would earn a $2/MMBtu profit on every MMBtu it can divert from Public Service to market sales, while Public Service customers would pay $3/MMBtu extra.

Q: How have similar market-power and reliability problems been dealt with when electric utilities transfer control of their regulated generation to unregulated affiliates?

A: In electric generation, comparable problems were addressed by

- formation of ISOs, to handle the dispatch of generation and limit the ability of owners to manipulate dispatch;
- market-monitoring functions within the ISOs, to identify potential market-power abuse;

[12] As I note above, Public Service has indicated that it intends that Newco compensate it for some peaking costs, but has not specified what costs will be credited to Public Service, nor whether it will propose that ratepayers be protected in any way from its actions regarding peaking supplies.

- Limiting, in many cases, the amount of generation that utility affiliates may own, or retaining regulatory authority to mitigate market power caused by the deregulated generation.

Despite these precautions, prices in the electric-energy markets have often exceeded the level that can be explained by fully competitive behavior, suggesting the presence of market power.

There is no plan for a regional gas-dispatching organization comparable to the ISOs (e.g., in PJM, New York or New England). Public Service is not proposing that the Board have any authority to control market power caused by the actions of Newco. Thus even the limited and inadequate protections in the electric markets would not be available for Public Service gas customers under the proposed transfer.

Q: How could the proposed transfer create market power in the wholesale electric market?

A: Were Newco to withhold gas capacity, or increase the price, it could push up the bid prices for gas-fired generators that depend on that capacity. The magnitude of the gas-price increase would depend on the gas-delivery supply and demand balance, the portion of available gas capacity controlled by Newco, and the prices of alternative fuels. Any such price increase could in turn increase market electric prices in PJM and New York.

As a result, the coal-fired and nuclear plants of PSEG Power would receive higher prices, as would its oil-fired steam plants, if #6 oil is less expensive than natural gas. Approximately 60% of PSEG Power's capacity is in coal, nuclear, and #6 oil plants, as follows.[13]

	MW
Nuclear	3,097
Coal	2,018
Oil (or Oil + Gas) Steam	1,954
Pumped Storage	200
Combined-Cycle	920
Combustion Turbine & Diesel	2,978

Every dollar-per-MMBtu increase in gas prices would add about $7/MWh to the market-clearing price if it were set by gas-fired combined-cycle plants, or about $10/MWh if the market-clearing price were set by gas-fired steam plants. The Company's 5,100 MW of baseload capacity could produce more than 120 GWh daily, for an increased profit from market power of about $1 million daily. These profits (in addition to the profits from the higher gas prices) would provide a significant incentive for Newco to restrict gas supply.

This combination of roles as a major gas supplier and major electric generator may allow Public Service to manipulate profitably prices in the electric market, especially after it is relieved of the obligation to provide BGS supply for Public Service electric customers in August 2002.

Q: Would Newco be constrained in manipulating gas prices, for fear of harming the economics of PSEG Power gas-fired plants?

[13]PSEG Power also has 1,660 MW of combined-cycle and combustion-turbine generation under development in PJM (at Bergen and Linden) and a further 2,750 MW in adjacent regions.

A: No. To the extent that Newco serves PSEG Power gas-fired plants, every extra dollar paid by PSEG Power would be another dollar received by Newco. The portion of any increase in market gas transportation costs that affected only the transactions between Newco and PSEG Power would have no effect on PSEG's bottom line. The higher market price for electricity generated by PSEG Power, and the higher market price for natural gas delivered by Newco to other customers other than PSEG Power, would both be windfalls for PSEG shareholders.

Q: Has Public Service presented any analysis of the ability of Newco to manipulate electric market prices?

A: No. The Company has made no effort to demonstrate that the transfer would not give Newco increasing control over prices in the wholesale market for electric energy.

Q: Is there any experience with gas supply affecting prices in a competitive market?

A: The experience of California over the last year or so demonstrates the sensitivity of electric market-clearing prices on delivered gas prices, and the potential for market abuse, even in a market with large amounts of non-gas capacity.[14]

Both the California Public Utilities Commission and Southern California Edison have accused El Paso Corporation, whose El Paso Pipeline is

[14]Of the 53,000 MW of generation in the California–southern Nevada reliability region reported by NERC, only about 500 MW are fired exclusively by gas, and another 3,200 MW comprise dual-fueled combined-cycle and combustion-turbine units, whose back-up fuel would be expensive #2 oil. California's supply system also includes about 1,400 MW of coal and nuclear generation in Arizona owned by Southern California Edison.

the major gas supplier to southern California, of manipulating prices through a marketing affiliate, El Paso Merchant Energy.[15] In February 2000, El Paso Merchant Energy won the rights to about 30% of the pipeline's capacity into California for a period of fifteen months. The California PUC and SCE claim that EPME withheld a large part of its gas capacity from the market, resulting in enormous escalation in gas prices. In early December, for example, Los Angeles city-gate prices were $42/MMBtu, compared to about $8/MMBtu in Phoenix, at the other end of the constrained pipeline. SCE claims that EPME overcharged by more than $800 million, and that the higher market gas prices cost California electric and gas consumers $3.7 billion.

Regardless of whether the run-up in California gas costs was the result of El Paso's market manipulation or just of high demand and limited supply (as El Paso claims), all observers appear to agree that tight gas supply has raised gas prices and contributed to the extraordinarily high electric prices in the state. The California example demonstrates the extent to which restrictions in gas supply can increase market prices for both gas and electricity.

B. The Effects on Ratepayers of the Transfer's Price

Q: What should be the Board's purpose in reviewing the pricing of the proposed purchase?

A: The Board's primary objective should be to ensure that ratepayers benefit from the full value of Public Service's supply resources, and that the value of those resources not be diverted to PSEG shareholders or other parties, unless ratepayers receive equal or greater value in compensation. The Board's

---

[15]El Paso Corporation also owns the Tennessee Pipeline, which serves New Jersey and much of the Northeast.

priority should be to avoid a situation in which ratepayers give up low-cost resources and must purchase higher-cost resources, either through Public Service–administered BGSS, competitively procured BGSS, or directly from third-party suppliers. The benefits of resources with below-market costs must remain available to all customers.

Q: Are there any obvious reasons for the Board to believe that the cost of Public Service's supply resources is less than their market value?

A: Yes. First, there is Public Service's proposal itself. If the Company really believed that the contracts cost more than their market (at least after the period in which the costs will flow through to Public Service ratepayers), it would not have offered to transfer them to an unregulated affiliate.[16]

Second, the interest of third-party suppliers in acquiring these resources at cost, through the proposed release and reassignment programs, suggests that they are priced below market.

Q: What evidence does Public Service offer regarding the value of the transferred contracts?

A: Public Service's evidence on the valuation of the contracts is contained in the testimony of Dr. Jeff Makholm.

Q: Does Dr. Makholm estimate the value of all aspects of the proposed transfer?

A: No. As Dr. Makholm acknowledged on cross examination, his testimony is limited to the valuation of Public Service's interstate transportation and

[16]Not surprisingly, Public Service acknowledged that the contracts would be worth more than their costs to Newco (IR RAR-T-15).

storage capacity. He does not provide any evidence regarding the value of the following:

- the aggregation of customer load through the Requirements Contract, and the transfer of that load to Newco, without any costs to Newco for acquiring the load. (The Requirements Contract is discussed by Company Witness David Wohlfarth.)
- Newco's right to control Public Service's peaking resources.[17]
- Newco's control over the interruptions of cogenerators and other non-firm customers, and the capacity and gas freed up by those interruptions.[18]
- The transfer of Public Service's gas-trading operations and staff to Newco.[19]
- The extraordinary pricing flexibility offered to Newco through the MPGS rate.[20]

---

[17]The Requirements Contract would require Public Service to "promptly implement [Newco]'s instructions with respect to Scheduling Coordination Services" (§2.4), These services include "decisions to dispatch [Public Service]'s Peak Shaving Facilities" (§1.16).

[18]The "Scheduling Coordination Services" that the Requirements Contract would require Public Service to "promptly implement [at Newco's] instructions" also include "decisions to curtail or interrupt retail deliveries under Rate Schedules CIG, CEG, ISG, TSG-NF or other non-firm rate schedules or the Non-Tariff Service Agreements." Mr. Wohlfarth discusses Newco's role in controlling the generation contracts at Tr. 196–200.

[19]Mr. Wohlfarth describes the acquisition of Public Service's experienced gas-trading personnel as adding significantly to the value of the contracts under Newco management (Tr. 516–518). The transfer of Public Service's trading operations to any other potential purchaser might produce equal or greater value.

[20]Remarkably, Public Service has still not fully described the extent of the price flexibility it is requesting for Newco in the MPGS rate, as I discuss in §V (infra, 53–57).

These aspects of the proposed transfer may be very valuable; Public Service simply provides no information about their value in the market.[21]

Q: Even within the limited scope of his analysis, did Dr. Makholm demonstrate that the value of the supply contracts are below their cost?

A: No. There are at least five problems with Dr. Makholm's analysis that make it largely irrelevant to determining the value of the resources, even without the Requirements Contract. Dr. Makholm

- ignores the premium value of firm supply.
- relies on prices from three warmer-than-average years.
- ignores the growth in gas-fired generation in New Jersey and downstream.
- models the value of the contracts under the existing regulatory scheme, rather than in a future restructured market with market power.
- ignores the potential for hedging, arbitrage, and other value-maximizing strategies.

Q: How did Dr. Makholm err in ignoring the firmness premium

A: Dr. Makholm compared the cost of Public Service's firm interstate pipeline resources with spot market-area prices for gas over the last three years. Gas-dependent consumers must pay more than the expected spot price of gas to ensure that they always have gas available. I know of no northeastern LDC that relies primarily (let alone exclusively, as in Dr. Makholm's analysis) on local spot purchases of gas to serve firm customers.[22] Mr. Hornby empha-

[21]Shell also believes that Dr. Makholm did not properly account for the revenues that could be earned from the transferred contracts (RAR-Shell-10).

[22]That may be a suitable strategy for serving interruptible loads of dual-fueled customers.

sizes the importance of firm gas supplies in his responses to RAR-Shell-4 and RAR-Shell-5.

Q: How did Dr. Makholm err in relying on prices from warmer-than-average years?

A: The 30-year average heating degree days (HDD) for Central Park (as a proxy for New Jersey and downstream areas) is 4,800 HDD, but the three years Dr. Makholm used in his analysis had only 4,220, 4,294, and 4,424 HDD.[23] While Dr. Makholm performed a weather-normalized analysis (supposedly for 2005, although he did not adjust for foreseeable changes, as I discuss below), he corrects only for the effect of daily temperature variations, not for annual weather changes. In a cold winter, storage (and environmentally limited dual-fuel use) is drawn down more quickly in both storage and market areas, resulting in higher prices for the rest of the winter and spring, and even into the summer and fall refill season. A 20-HDD day in February, following a cold January, will result in higher prices than the same day following a mild January, all else equal. Dr. Makholm made no attempt to adjust for this difference.

Q: How did Dr. Makholm err in ignoring the growth in gas-fired generation?

A: Dr. Makholm assumed that gas demand (including the load of electric generators) and pipeline transportation capacity would grow with the general growth in the economy. In fact, gas demand from electric generators is

---

[23]Dr. Makholm did not select these years arbitrarily. These are the three most recent years, and it is not clear that prices from earlier years will provide more accurate data in this rapidly changing market. My point is that Dr. Makholm's analysis does not necessarily provide useful information on the average market value of the resources over a typical distribution of weather.

growing much faster than the economy, and pipeline capacity is unlikely to be expanded proportionately.

A huge amount of new gas-fired generation has been announced in the last few years in PJM, New York and New England.

- The PJM ISO reports that developers of projects (mostly gas-fired) amounting to 44,000 MW of generation have requested interconnection studies.
- Almost 11,000 MW is in licensing in New York.
- Some 1,800 MW of new gas-fired generation entered service in New England during the period of Dr. Makholm's data. The New England ISO expects another 6,000 MW of gas-fired generation to be added by 2003, and reports that developers have plans to add 11,600 MW by 2005.

Not all the planned generation will actually be built on the current schedules, which is a good thing from the perspective of gas supply. Providing gas to just 6,000 MW in each of the three power pools would require 3,000 MMcf/d of pipeline capacity, compared to a total delivery capacity to the Northeast of about 13,000 MMcf/day.[24]

Q: Will all the new gas-fired generation burn gas all through the year?

A: Much of the gas-fired generation will have an alternative fuel, but that fuel (mostly #2 distillate oil) is usually quite expensive, which will tend to put upward pressure on the cost of gas. In addition, environmental restrictions

[24]Furthermore, that's for the EIA definition of the Northeast, including Virginia, where additional gas-fired generation is also likely to be constructed.

may limit the number of hours the generators can operate on the alternative fuel.[25]

Q: Is the addition of pipeline capacity likely to keep pace with the addition of gas-fired generation?

A: No. Since the dual-fueled generators do not use gas at peak, they are not likely to contract for firm year-round supply. While they increase demand in most of the year, they do not usually motivate pipelines to add capacity.

As a result, the new dual-fueled generation is likely to increase demand on the existing pipeline resources (including those Public Service would transfer to Newco) and firm up the value of gas-delivery capacity in the warmer months and in mild years. These are the times, even prior to the termination of the Requirements Contract in 2004 or 2007, that Newco would have the greatest capacity available (in excess of Public Service's customer needs) for sale.[26] Under current arrangements, Public Service would use the excess capacity at these times to reduce its costs, and hence reduce rates; after the proposed transfer, Newco (and hence Public Service shareholders) would retain those revenues.

Even if all the additions of gas-fired generation were firm gas users, Public Service has not presented any evidence that the planned pipeline expansions are likely to match the increases in demand.

Q: How would the value of the contracts change in a future restructured market with market power?

---

[25]A typical limit would be 500 hours annually, or about 20 days. Some projects are only allowed to burn oil when gas is unavailable.

[26]Newco might choose to sell delivered gas in the market area, rather than selling capacity.

A: The exercise of market power by any participant in the Northeast natural-gas transportation market would tend to increase the value of the contracts. That would be particularly true if the entity exercising the market power were Newco.

Q: What is your basis for suggesting that hedging, arbitrage, and other strategies might increase the value of the contracts, compared to the estimate prepared by Dr. Makholm?

A: Dr. Makholm simply estimated the price that might be earned from releasing the pipeline capacity on a daily basis. His modeling of storage is a little more complicated, but basically appears limited to the estimation of a single annual cycle of injection and withdrawal.

Newco would have many other options for the use of the contracts, including arbitrage between pipelines (particularly since Public Service is unusual among utilities in being supplied by four major pipeline systems). Indeed, Public Service acknowledges that the contracts are more valuable than Dr. Makholm suggests, due to opportunities in gas trading and financial derivatives (IR RAR-T-15, Tr. 515–517). While Public Service describes Newco as being uniquely positioned to take advantages of these options, it has not demonstrated that the additional value lies in Newco (which, after all, does not even exist yet) rather than the contracts themselves.

Q: What is the cumulative effect of the factors that Dr. Makholm ignored?

A: Combining the effects of the additional gas-fired generation, the higher prices in normal and colder-than-normal weather, the incremental value of firm supply, the prospect of future exercise of market power, and the optimized use of the contracts, the actual value of Public Service's resources in the future is likely to be significantly greater than Dr. Makholm estimates.

Q: How could the true market value of the contracts be determined?

A: The standard method of valuing an asset that one party (in this case, Public Service) no longer wants is to offer it for sale in a competitive market.[27] This is the way that Atlantic City Electric established the value of its generating plants: though a competitive auction with multiple bidders. This has become the standard procedure for disposal of electric power resources, whether owned generation or purchase contracts.[28]

Similarly, Atlantic has identified the least-cost BGS supply by competitive bid. Most other utilities of which I am aware that have needed to acquire power supply to support standard-offer service have similarly been acquiring that supply competitively.

The obvious implication is that, if Public Service were to dispose of its supply contracts, it should do so by putting the contracts up for competitive bidding. If bidding out all the contracts were not feasible for some reason, Public Service might bid out a representative cross-section of the contracts to establish a benchmark price for the remainder.

I am not aware of any economic literature that suggests that transferring a resource at cost, as the Company proposes, is apt to yield a higher price than a competitive bid. Indeed, auction theory suggests that competitive bidding beats negotiation, and the more competition, the better.[29] This would

---

[27]I do not mean to suggest that Public Service should want to dispose of these contracts at this time, or that the Board should allow it.

[28]Even auctions have not always provided prices equal to the value of the resources within a few years, especially with a volatile market. Examples include the GPU and United Illuminating fossil plants that were resold by their purchasers at substantial profits, or the divested California generation.

[29]Bulow, Jeremy, and Paul Klemerer. 1996. "Auctions Versus Negotiations" *American Economic Review* 86(1): 180–194.

be particularly true where the alternative to competition is allowing Public Service to negotiate an exclusive arrangement with its affiliate.

Q: Is there any experience comparing the negotiated sale of resources to the price in a competitive market?

A: Yes. There are examples of electric generation assets for which negotiated sales prices were announced, but later competition resulted in higher prices.

The clearest example of this type is the sale of the Nine Mile Point 1 and 2 nuclear plants. On June 24, 1999, after a period of exclusive negotiation, Niagara Mohawk Power Corp (NiMo) and New York State Electric and Gas (NYSEG) announced their intent to sell their 41% and 18% shares in Nine Mile 2, as well as NiMo's wholly-owned Nine Mile 1, to AmerGen Energy. NiMo was to receive approximately $135 million ($63.55 M for Unit 2 and $71.7 M for Unit 1), while NYSEG would have received $27.9 million. A co-owner of the plant, Rochester Gas and Electric (RG&E), chose to exercise its right of first refusal for the capacity (at the same price), in conjunction with Entergy. The New York Public Service Commission Staff recommended that the Commission reject the sale to either purchaser at those prices. The utilities asked the PSC to dismiss their petitions for approval of the sale, and proceeded to conduct a competitive auction, including the portions of Unit 2 owned by RG&E (14%) and Central Hudson Gas and Electric (9%).

In December 2000, the results of the auction were announced. The winning bidder was Constellation Nuclear, who is to pay $815 million, including $418 million to NiMo ($290 million for Unit 2, $128 million for

Unit 1).[30] The competitive price is about three times the negotiated price for NiMo, and nearly five times the negotiated price for NYSEG.

A similar, if less dramatic, series of events played out in the sale of the New York Power Authority (NYPA) nuclear plants, FitzPatrick and Indian Point 3. On November 2, NYPA announced the results of exclusive negotiations with Entergy, resulting in a series of sales agreements worth about $500 million. Dominion made an unsolicited offer, even without the opportunity to perform a full review of the plants, and the ensuing rounds of counter-offers ended with NYPA setting on selling to Entergy, but with additional payments worth roughly $100 million, or about 20% of the original price. Fully competitive bidding might have produced an even higher price.

Again, AmerGen reached an agreement to purchase Vermont Yankee in October 15, 1999, following exclusive negotiations. The agreement was described by the Vermont Public Service Board as "a complex one involving several inextricably interrelated agreements for purchase of the nuclear power station and for long-term power-purchase commitments. Overall, the proposal was described (even by one Petitioner's own financial analyst) as 'break-even from a financial point of view.'" (Docket No. 6300, Order of 2/14/01, 2). Under pressure from the PSB, AmerGen sweetened the deal in November 2000 to a purchase price of $23.8 million. In January 2001, Entergy made an unsolicited offer of $50 million, more than twice AmerGen's revised offer. AmerGen then modified its offer further, and claimed that its third proposal was slightly better than Entergy's offer. Other potential purchasers indicated an interest in bidding on the plant if the

---

[30]Constellation will also pay interest for deferring payment of half the purchase price over a five-year period.

process were opened up. The Vermont PSB dismissed the petition to approve the negotiated AmerGen offer, and Vermont Yankee announced that it would be conducting an auction to determine the value of the plant.

In all three of these cases, competition (even under serious constraints) between bidders produced higher offer prices than did the best efforts of the sellers in negotiations. This was so, even though the negotiations were conducted with multiple bidders. It is difficult to believe that Public Service, negotiating effectively with itself, would come up with as good a deal for ratepayers as could be obtained through a competitive auction.

Q: Are there any aspects of the proposed transfer that increase the value to Newco?

A: Yes. In addition to the general option that Newco would have to terminate contracts as they expire or come up for renewal, the proposed transfer would give Newco additional options.

The Joint Position would give Newco the option of turning back to Public Service 50% of contracts in 2004, after the initial contract term, unless Public Service extends to the contract to 2007. So if contracts are above market value in 2004, Public Service ratepayers would assume a portion of the cost regardless of what Public Service elects. That is, if Public Service extends the contract, ratepayers would bear the extra costs for three more years, but if Public Service terminates, Newco would return half the contracts, and ratepayers would pay the excess cost of those contracts.

There would be no comparable symmetric option for ratepayers; the Board could not order Newco to return 50% of the contracts to Public Service, if it found that the contracts were less expensive than alternatives at the end of the Requirements Contract.

Q: Is the value of a resource in a competitive market easily and reliably determined by the sort of administrative determination that Dr. Makholm attempts in his analysis?

A: No. In the cases in which regulators have estimated the value of electric generation assets, and the same assets have then been sold through competitive processes, the actual prices have been vastly different than the administratively determined valuations. I am aware of three such examples.

The GPU Fossil Sale

In June 1998, the Pennsylvania PUC estimated the market value of the generation assets of the Pennsylvania GPU operating companies (Metropolitan Edison and Pennsylvania Electric). This estimate was derived from a detailed evidentiary record, market-price projections by several parties, and recommended decisions and orders that dealt with many of the inputs in great detail. In July through November 1998, GPU reached agreements for the sale of all these generation assets to Sithe. The sale was consummated in November 1999. In February 2000, Sithe announced the resale of all the former GPU assets to Reliant, at a total price 25% greater than the initial sales. The initial sales prices were nearly double those estimated by the PUC, as follows:

	Metropolitan Edison	Pennsylvania Electric	Total
PUC Estimate	$382 million	$834 million	$1,216 million
Initial Sales Price[31]	$727 million	$1,574 million	$2,301 million
Excess of Price over Estimate	90%	89%	89%

[31]These values use a minimum price for Three Mile Island of $100 million. AmerGen may pay GPU another $80 million depending on future market prices. In addition, AmerGen did not require GPU to prefund the full estimated decommissioning costs, effectively assuming some $89 million in decommissioning liability, which could be considered part of the purchase price.

The resale to Reliant, assuming that the value of all the assets increased equally, indicates that the market value of the resources was more than twice the administrative estimate.

Duquesne Generation Sale

In May 1998, the Pennsylvania PUC issued a decision on the restructuring of Duquesne Lighting (Docket No. R-00974104). The portion of that decision of stranded costs is complex, but it appears that the PUC (Order, 139) estimated that market value of Duquesne's generation as $111 million, plus an adjustment for productivity gains of $13 million, for a total valuation of $124 million.

Duquesne then traded its joint ownership interests in nuclear and coal plants to FirstEnergy (the majority owner of each unit) for sole ownership of additional coal units. In September 1999, Duquesne agreed to sell its entire collection of wholly owned generation (its older units, plus the new ones acquired from FirstEnergy) to Orion Power for $1.7 billion, or sixteen times the price estimated by the Pennsylvania PUC.

The Millstone Sale

In July 1999, the Connecticut Department of Public Utility Control estimated the market value of Unit 2 of the Millstone nuclear plant at $25/kW, and the market value of Unit 3 as $185/kW (Docket No. 99-02-05, 44).[32] In August 2000, Dominion Resources won the auction for Unit 2 (875 MW) and the 93.5% of Unit 3 (1,075 MW) that Northeast Utilities and minority owners chose to sell as a block. That capacity would have cost $221 million at the market values estimated by the DPUC. The actual sales price was $1.3 billion, or six times the administrative estimate.

[32]Unit 1 had been retired.

C. *The Effect of the Proposed Transfer on Reliability*

Q: How could the proposed transfer adversely affect the reliability of gas supply to Public Service customers?

A: There are two groups of issues that raise concerns about the reliability of gas supply: the loss of a unified planning function, and the incentives to Newco.

Q: What is your concern about the loss of a unified planning function?

A: The basic problem is that no entity would be responsible for ensuring adequate gas supplies to serve firm Public Service customers. During the period of the Requirements Contract, Newco would be responsible for maintaining sufficient capacity to supply BGSS. It is not clear how it would meet this responsibility (or if it would even consider that it had such a responsibility) if third-party suppliers dump their Public Service customers but retain the permanently released capacity for sales to other markets. As I read the Joint Position, especially Schedule 4, third-party suppliers would be required to return capacity to Newco only when the released contracts come up for renewal. At the very least, the Board should expect Public Service to explain how it would ensure sufficient capacity in the absence of a requirement that released capacity follow customer load that returns to BGSS.

After the period of the Requirements Contract, even the nominal responsibility of Newco for BGSS would end.

Q: Does a similar problem arise in the restructured electric markets?

A: Yes. California's problems are partially attributable to the weakness of planning structures in the state.[33] To avoid those problems, most other

[33]The longstanding comprehensive biennial statewide electricity-planning process was curtailed in 1995, as the state moved toward restructuring.

restructurings of electric markets have left the utility with some responsibility for contracting for supply on a multi-year basis. In addition, there is usually an independent system operator with responsibility for capacity planning.

The Public Service proposal does not include either long-term utility acquisition of supply resources or an independent system operator.

Q: How could Newco's incentives imperil reliability?

A: Newco's interest in maximizing its profits in the unregulated wholesale market may result in its dispatch of resources in a manner that imperils the reliability of gas supply for firm Public Service customers. For example, Newco may dispatch Public Service's peaking supplies early in the heating season, to free up Newco resources for sale into the competitive market. As a result, LNG supplies may be inadequate to withstand a later cold snap.

Similar problems can result if Newco leaves too little gas in underground storage, or if it commits to excessive levels of firm off-system sales.

Q: In Section III, you mentioned the problems with reliability of electric supply in California. Is inadequate reliability a greater problem for electricity or natural gas?

A: Insufficient supplies are much worse a problem for natural gas. When electric supplies are inadequate, a utility can institute rolling blackouts, shutting down areas of its system for short periods, and restoring power to one area as it turns off the next. These rolling blackouts are inconvenient, and impose some costs (and even some safety hazards), but are not much worse than the random outages most customers experience periodically due to transmission and distribution problems.

The situation with gas is quite different. Once gas pressure falls below the level necessary to keep pilot lights lit (resulting in flameout), the utility must shut down the area, to prevent gas leakage and explosions. Before the gas can be restored, utility personnel must enter each building, identify the appliances with pilot lights, and ensure that all pilot lights are shut off. Once gas is restored to each building, each pilot must be lit again. This process can take days, even for relatively small areas. Widespread flameout in the winter could result in residents facing the choice of evacuating to areas with adequate fuel supply, or possibly freezing at home. The costs of evacuation, service restoration, and cleanup of damaged buildings could make flameout a significant disaster, even if no lives were lost.

Utilities and governments take extraordinary measures to avoid flameout. In the winter of 1980–81, a series of errors by Boston Gas and other Massachusetts gas utilities brought the state close to flameout conditions in an unusual December cold snap. The problems included pursuit of interruptible sales (which benefited shareholders) well into the heating season, failing to provide supply for nominally interruptible customers who had never been interrupted and had no alternative fuel supply, and relying on resources that were not as firm as the utilities expected. The latter category included "best efforts" gas contracts, imported LNG (which became unavailable when a ship sank in the harbor in Algeria, blocking the terminal), and propane-air injection (which quickly exhausted local supplies, as the cold snap drove up other demands for propane). To conserve gas and avoid flameout, the Governor shut down the Commonwealth's government, all the state's public schools, and most businesses for several days.

Under Public Service's proposal, Newco (and to a lesser extent the third-party suppliers) may be tempted to take the same kinds of chances with fuel supply and non-firm sales that brought the Massachusetts utilities so close to disaster 20 years ago.

D. The Proposed Transfer and the Design of Basic Gas-Supply Service

Q: How would the proposed transfer of contracts to Newco affect future BGSS options?

A: As the matter now stands, the Board has many options in structuring a reasonably-priced, reliable BGSS, using combinations of Public Service resources and market purchases. The transfer of Public Service's resources to Newco would foreclose many of those options.

Since a well-designed BGSS is essential to a smooth transition to a competitive market, and may be essential for small customers for the foreseeable future, the Board should avoid any actions that would impede its ability to implement effective, reliable BGSS services.

1. Importance of Basic Gas-Supply Service for Successful Gas Competition

Q: Why is BGSS an important part of establishing a competitive gas supply market?

A: It may be reasonable for regulators to assume that large customers can shop around for appropriate gas-supply options, understand contractual obligations in a complex and volatile market, assess the financial qualifications of third-party suppliers, form sophisticated purchasing groups, and absorb the consequences of bad decisions.[34] For many small customers, and especially residential customers, these energy-procurement decisions are confusing, time-consuming and difficult. Especially in the transition period, when ratepayers

[34]The experience in the Northwest indicates that even large customers may be overwhelmed by changes in energy markets. Some large industrial firms have gone out of business due to their reliance on rapidly escalating spot electricity purchases.

are still getting used to the idea of competitive retail markets for natural gas, many customers are likely to depend on the utility supply alternative.

Experience in the electric markets in California, PJM, and New England has demonstrated that third-party suppliers are happy to serve customers when market prices are low, but abandon those customers when prices rise and markets become unstable. This has been especially true where third-party suppliers have been competing against fixed prices for the utility's standard offer (or whatever the equivalent to BGSS is called in each state). It has also occurred for San Diego Gas and Electric, whose standard-offer price is the monthly average ISO price, and in Massachusetts, where utilities charge returning customers (including those dumped by third-party suppliers) market prices for default service.

Having a regulated backstop price, to ensure stable, just and reasonable rates, is an essential aspect of any transition to competition that seeks to avoid the disruptions so prevalent in the electric markets (and especially in California).[35] As I discuss below, the Board has many options in the form of that backstop, and the role of Public Service's resources in maintaining it.

Q: How should the Board coordinate any decisions about the transfer of Public Service's supply resources to other parties with decisions about BGSS?

A: The Board should first resolve the nature of BGSS service in the long term, for all its jurisdictional utilities, and make sure that the BGSS system is

---

[35]Shell's witness Mr. Hornby described as essential that the Board "be able to monitor the reasonableness of the pricing under BGSS Service" and that BGSS be "subject to Board regulation," through the period of transition to a fully competitive market (Tr. 620).

operating properly, before doing anything that would remove Public Service's supply resources from regulatory control.

The basic decisions about BGSS should be made on a statewide basis, although the Board may wish to implement different experimental or pilot programs for alternative BGSS systems for the various utilities. During the transition period, while the Board is settling on and testing the eventual form of the BGSS, and ensuring that the market is operating effectively, it should not irrevocably transfer control of Public Service's resources.

2. Range of Options for Basic Gas-Supply Service

Q: How might the Board ultimately decide to structure BGSS, and how would the transfer affect the Board's ability to implement those BGSS approaches?

A: There are a number of possible approaches, of which I have identified the following examples:

- Public Service could supply the BGSS directly from its resources, at regulated rates. Third-party suppliers could compete with supply service from capacity released by Public Service (under the type of program proposed in the Joint Position, but with improved protections for customers) or from market sources. This option would not be possible if the transfer is approved.
- Public Service could supply the BGSS at the price of open-market wholesale purchases, with overlapping purchase contracts of one to a few years, to provide a stable, market-priced service against which third-party suppliers could compete. To further stabilize total gas bills, Public Service could sell its existing resources into the market on a

similar time scale, and credit the profit against delivery rates. Under this scheme, if market prices and BGSS are high in some period, the credit to delivery rates would also be high, providing a hedge for all Public Service firm customers, whether they take supply from BGSS or a third-party supplier. This hedging option would be lost if the transfer is approved.

- The Board could have Public Service bid out the direct retail BGSS, under Board-approved consumer protections, to one or multiple providers. The Company could use its resources to provide the same type of hedge as in the previous option. Again, this hedging opportunity would be lost if the transfer were approved.
- Instead of periodic sales of resources into the market in either of the two preceding options, Public Service could resell or transfer rights to its resources permanently or for a long period, and use the proceeds to reduce delivery rates. Transferring the resources at cost to Newco would eliminate any potential gain for ratepayers.

The Joint Position would foreclose all these options for the Board. BGSS would be limited to a short-term market service, exposing residential customers to the whims of the gas market. Public Service offers "continuation of the Company providing BGSS service for at least six years into the future" (Wohlfrath, 7), but only at non-hedged prices. As demonstrated in the electric markets, short-term prices can be volatile and unexpectedly high. Newco would have a great deal of flexibility in selecting the price it chooses to charge customers, so prices may be very high and very volatile.

The California experience demonstrates the problems that can result from the divestiture of utility supply resources and the attendant loss of hedging.

V. The Joint Position

Q: Does the joint position resolve your concerns?

A: No. Most of the problems with the original filing remain in the Joint Position, as follows:

- the failure to determine the market value of Public Service's supply resources and to fully compensate ratepayers for the loss of those resources.
- the loss of price stability in BGSS, initially for C&I and ultimately for all customers.
- The lack of any mechanism for ensuring reliable supply to Public Service's customers.
- Continued vagueness on many points, including the price of the BGSS.

In addition, the Joint Position does not require third-party suppliers to turn back capacity if the customers for whom they were assign the capacity leave the third-party supplier (e.g., because the third-party supplier increased its rates) or are abandoned by the third-party suppliers.[36] This may result in higher costs and potentially in reliability problems.

The treatment of residential customers under the Joint Position has nothing to recommend it. The current system would be essentially unchanged for residential customers for three years: Public Service would sell its capacity at cost to Newco, which would then sell it back to Public Service, for sale to the residential customers. The point of these transactions is not clear,

---

[36]The third-party suppliers would be required to return any excess capacity to Newco at the contract termination date of the pipeline or storage contract, under Provisions A.9, B.11 and B.12 of Joint Position Schedule 4. I have not found any comparable provisions requiring return of capacity when customers return to BGSS.

other than to commit the Board to a course of action three years into the future, and to allow Newco to profit from off-system sales.

Public Service has proposed to force ratepayers onto monthly short-term gas prices (the MPGS rate) immediately for non-residential customers or April 1, 2004 for residential customers, without any stable default service.[37] As I describe above, the lack of a price stability in the BGSS is similar to the provisions in California, where the customers and the utilities have shared the pain of unstable prices. Neither the Board nor anyone else has any idea what market conditions will be like in 2004, and committing now to remove the price stability of long-term pipeline contracts could be like a time bomb. The Board has not shown any desire to remove those protections in the short term; it is not clear how committing to remove those protections at a definite point in the future would be any better.

While the Joint Position offers Public Service the option of extending the Requirements Contract another three years, to 2007, that contract would then be priced at monthly market prices, and would provide no price protection to ratepayers.

Q: Is Mr. Wohlfarth correct that "all gas customers [will] be free to either choose a third-party supplier or the Company to provide gas commodity based solely on price and the quality of service" in 2004?

---

[37]According to the Joint Position, the spot-market prices would initially be based on prices in the producing areas plus a fixed transportation (or "Non-Gulf") charge, with the transportation charge becoming "market-based" on January 1, 2004. In other places in the record, Public Service has indicated that the transportation charge for residential customers would be fixed. The Company has not provided an explanation of how either the Gulf cost of gas or the market-based transportation cost would be set. In any case, it appears that Public Service intends to give Newco the right to vary the MPGS price over a wide range, without regard to cost or to actual market prices.

A: This claim is somewhat misleading, in two ways. First, the Company would not be able to provide any pricing benefits, since Provision 8 of the Joint Position limits the Company's BGSS pricing to monthly spot prices, "Residential customers shall be priced under rate schedule MPGS at a market price, effective April 1, 2004."[38] Second, the third-party-supplier option really would not provide any quality of service: Public Service would determine delivery pressure, leak response time, and everything else people consider to be service.[39]

Q: Is the proposed Capacity Release program sufficient to mitigate Newco's control of gas supply and give customers a meaningful choice?

A: It is not clear that the Capacity Release program proposed by Public Service would be effective in achieving these goals. For example, residential and other small customers can be expected to respond slowly to high charges for MPGS, especially if Newco contents itself with charging rates only modestly in excess of market prices.

Even the emergence of a small number of large third-party suppliers may do little to moderate Newco's market power. The California experience suggests that control of even a few percent of a scarce resource may be sufficient to allow a supplier to exercise market power. The large third-party suppliers may also exert market power.

---

[38]The Joint Position states that the MPGS price will be entirely market-based by January 1, 2003, but the Company sometimes maintains that the Non-Gulf Component will be cost-based until 2007 (RAR-T-63; RAR-T-152; Tr. 429–430).

[39]The third-party suppliers can control the speed and quality of response to questions about its supply bills, but that is about all.

Q: Are the third-party suppliers likely to contract with pipelines for expansion of capacity?

A: I find that possibility unlikely. Pipeline contracts for new supplies typically have very long durations for marketers with no dedicated customers. It is one thing to sign a 20-year (or even 10-year) contract for service to a power plant. It is much more speculative to sign such a contract to serve thousands of small customers, who may well switch suppliers. The obligation to the pipeline may be a substantial risk.

Another useful perspective is to ask why third-party suppliers would contract with pipelines in the future for new supplies to serve firm customers, if they have not done so extensively in the past.

In addition, the long lead time required for new pipeline capacity to be planned, sited, permitted, and built would make new construction a poor defense against any abuse of market power by Newco or other large suppliers.

Q: Does the Addendum to the Joint Position resolve any of the concerns you raise above?

A: No. I read it as providing non-PSEG generators in New Jersey with access to capacity that Newco declares to be surplus and offers to its generation affiliates. This appears to be a very limited provision, applying only when Newco decides to declare capacity surplus in the long term, and only when Newco is actually offering capacity to a generation affiliate. It is not clear that this provision would ever apply, or if it did that it would limit Newco's ability to control the price of the released capacity. Newco can charge PSEG Power any price it selects, without adversely affecting PSEG's bottom line, since the revenues to Newco equal the costs to PSEG Power.

Q: To the extent that the Board finds desirable aspects of the Joint Position, such as increased opportunities for capacity release to third-party suppliers, can those be achieved without the transfer of Public Service's resources to Newco?

A: Yes. If the Board decides to implement those features of the Joint Position, Public Service can release capacity, provide incentives, and otherwise encourage development of a competitive market, without irrevocably relinquishing control over vital resources.

Even the transfer of certain risks and of operating control away from Public Service can be achieved without permanently committing the Board to placing Public Service gas customers on prices based on the monthly spot market. For example, the Board could instruct Public Service to seek bids for a management contract through the remainder of the transition period, based on fixed or formula prices.

Q: Does this conclude your testimony?

A: Yes.

Schedule PLC-1

Paul L. Chernick

Resource Insight, Inc.
347 Broadway
Cambridge, Massachusetts 02139-1715

SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

"Environmental Regulation in the Changing Electric-Utility Industry" (with Rachel Brailove), *International Association for Energy Economics Seventeenth Annual North American Conference* (96–105). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Jonathan Wallach), *1996 Summer Study on Energy Efficiency in Buildings,* Washington: American Council for an Energy-Efficient Economy 7(7.47–7.55). 1996.

"The Allocation of DSM Costs to Rate Classes," *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. May 1994.

"Environmental Externalities: Highways and Byways" (with Bruce Biewald and William Steinhurst), *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. May 1994.

"The Transfer Loss is All Transfer, No Loss" (with Jonathan Wallach), The *Electricity Journal* 6:6 (July 1993).

“Benefit-Cost Ratios Ignore Interclass Equity” (with others), *DSM Quarterly*, Spring 1992.

“ESCos or Utility Programs: Which Are More Likely to Succeed?” (with Sabrina Birner), *The Electricity Journal* 5:2, March 1992.

“Determining the Marginal Value of Greenhouse Gas Emissions” (with Jill Schoenberg), *Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II*, July 1991.

“Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs” (with E. Caverhill), *Proceedings from the Demand-Side Management and the Global Environment Conference*, April 1991.

“Accounting for Externalities” (with Emily Caverhill). *Public Utilities Fortnightly* 127(5), March 1 1991.

“Methods of Valuing Environmental Externalities” (with Emily Caverhill), *The Electricity Journal* 4(2), March 1991.

“The Valuation of Environmental Externalities in Energy Conservation Planning” (with Emily Caverhill), *Energy Efficiency and the Environment: Forging the Link*. American Council for an Energy-Efficient Economy; Washington: 1991.

“The Valuation of Environmental Externalities in Utility Regulation” (with Emily Caverhill), *External Environmental Costs of Electric Power: Analysis and Internalization*. Springer-Verlag; Berlin: 1991.

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian Goodman), *Gas Energy Review*, December 1990.

“Externalities and Your Electric Bill,” *The Electricity Journal*, October 1990, p. 64.

“Monetizing Externalities in Utility Regulations: The Role of Control Costs” (with Emily Caverhill), in *Proceedings from the NARUC National Conference on Environmental Externalities*, October 1990.

“Monetizing Environmental Externalities in Utility Planning” (with Emily Caverhill), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian Goodman), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“A Utility Planner’s Checklist for Least-Cost Efficiency Investment” (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy" (with John Plunkett and Jonathan Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Incorporating Environmental Externalities in Evaluation of District Heating Options" (with Emily Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment," (with John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference*, June 1990.

"Incorporating Environmental Externalities in Utility Planning" (with Emily Caverhill), *Canadian Electrical Association Demand Side Management Conference*, May 1990.

"Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?" in *Proceedings of the NARUC Second Annual Conference on Least-Cost Planning*, September 10–13 1989.

"Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities," in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23 1989.

"The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal" (with John Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy, 1988.

"Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels," in *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 1988, pp. 553–557.

"Capital Minimization: Salvation or Suicide?," in I. C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, 1987, pp. 63–72.

"The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," in *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, Albuquerque, New Mexico, April 1987, pp. 36–42.

"Power Plant Phase-In Methodologies: Alternatives to Rate Shock," in *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 547–562.

"Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System" (with A. Bachman), *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 2093–2110.

"Forensic Economics and Statistics: An Introduction to the Current State of the Art" (with Eden, P., Fairley, W., Aller, C., Vencill, C., and Meyer, M.), *The Practical Lawyer*, June 1 1985, pp. 25–36.

“Power Plant Performance Standards: Some Introductory Principles,” *Public Utilities Fortnightly*, April 18 1985, pp. 29–33.

“Opening the Utility Market to Conservation: A Competitive Approach,” *Energy Industries in Transition, 1985–2000*, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November 1984, pp. 1133–1145.

“Insurance Market Assessment of Technological Risks” (with Meyer, M., and Fairley, W) *Risk Analysis in the Private Sector*, pp. 401–416, Plenum Press, New York 1985.

“Revenue Stability Target Ratemaking,” *Public Utilities Fortnightly*, February 17 1983, pp. 35–39.

“Capacity/Energy Classifications and Allocations for Generation and Transmission Plant” (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, Institute for Public Utilities, Michigan State University 1982.

Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (with Fairley, W., Meyer, M., and Scharff, L.) (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December 1981.

Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September 1977.

REPORTS

“Review and Critique of the Western Division Load-Pocket Study of Orange and Rockland Utilities, Inc.” (with John Plunkett, Philip Mosenthal, Robert Wichert, and Robert Rose). 1999. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

“Avoided Energy Supply Costs for Demand-Side Management in Massachusetts” (with Rachel Brailove, Susan Geller, Bruce Biewald, and David White). 1999. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

“Performance-based Regulation in a Restructured Utility Industry” (with Bruce Biewald, Tim Woolf, Peter Bradford, Susan Geller, and Jerrold Oppenheim). 1997. Washington: NARUC.

“Distributed Integrated-Resource-Planning Guidelines.” 1997. Appendix 4 of “The Power to Save: A Plan to Transform Vermont’s Energy-Efficiency Markets,” submitted to the Vermont PSB in Docket No. 5854. Montpelier: Vermont DPS.

“Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests” (with Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter

Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People's Counsel.

"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Jonathan Wallach). 1996. Concord, N.H.: NH OCA.

"Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities" (with Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

From Here to Efficiency: Securing Demand-Management Resources (with Emily Caverhill, James Peters, John Plunkett, and Jonathan Wallach). 1993. 5 vols. Harrisburg, Penn: Pennsylvania Energy Office.

"Analysis Findings, Conclusions, and Recommendations," vol. 1 of "Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro" (with Plunkett, John, and Jonathan Wallach), December 1992.

"Estimation of the Costs Avoided by Potential Demand-Management Activities of Ontario Hydro," December 1992.

"Review of the Elizabethtown Gas Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach, John Plunkett, James Peters, Susan Geller, Blair. Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

Environmental Externalities Valuation and Ontario Hydro's Resource Planning (with E. Caverhill and R. Brailove), 3 vols.; prepared for the Coalition of Environmental Groups for a Sustainable Energy Future, October 1992.

"Review of Jersey Central Power & Light's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

"The AGREA Project Critique of Externality Valuation: A Brief Rebuttal," March 1992.

"The Potential Economic Benefits of Regulatory NO_X Valuation for Clean Air Act Ozone Compliance in Massachusetts," March 1992.

"Initial Review of Ontario Hydro's Demand-Supply Plan Update" (with David Argue et al.), February 1992.

"Report on the Adequacy of Ontario Hydro's Estimates of Externality Costs Associated with Electricity Exports" (with Emily Caverhill), January 1991.

"Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities," (with John Plunkett et al.), September 1990. Filed in NY PSC Case No. 28223 in re New York utilities' DSM plans.

"Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica's Power Needs," (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with Ian Goodman and Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with Emily Caverhill), Boston Gas Company, December 22 1989.

"Conservation Potential in the State of Minnesota," (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18 1981.

PRESENTATIONS

"Distributed Utility Planning." With Steve Litkovitz. Presentation to the Vermont Distributed-Utility-Planning Collaborative, November 1999.

"The Economic and Environmental Benefits of Gas IRP: FERC 636 and Beyond." Presentation as part of the Ohio Office of Energy Efficiency's seminar, "Gas Utility Integrated Resource Planning," April 1994.

"Cost Recovery and Utility Incentives." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

"Comparing and Integrating DSM with Supply." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"DSM Cost Recovery and Rate Impacts." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

“Cost-Effectiveness Analysis.” Presentation as part of “Effective DSM Collaborative Processes,” a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

“Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling” (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference; June 1993.

“Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making.” Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

“Cost Recovery and Decoupling” and “The Clean Air Act and Externalities in Utility Resource Planning” panels (session leader), DSM Advocacy Workshop; April 15 1992.

“Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs,” Energy Planning Workshops; Columbia, S.C.; October 21 1991;

“Least Cost Planning and Gas Utilities.” Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

“Least-Cost Planning in a Multi-Fuel Context,” NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

“Accounting for Externalities: Why, Which and How?” Understanding Massachusetts’ New Integrated Resource Management Rules; Needham, Massachusetts, November 9 1990.

“Increasing Market Share Through Energy Efficiency.” New England Gas Association Gas Utility Managers’ Conference; Woodstock, Vermont, September 10 1990.

“Quantifying and Valuing Environmental Externalities.” Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy’s Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

“Conservation in the Future of Natural Gas Local Distribution Companies,” District of Columbia Natural Gas Seminar; Washington, D.C., May 23 1989.

“Conservation and Load Management for Natural Gas Utilities,” Massachusetts Natural Gas Council; Newton, Massachusetts, April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, N.H., January 22–23 1989.

“Assessment and Valuation of External Environmental Damages,” New England Utility Rate Forum; Plymouth, Massachusetts, October 11 1985; “Lessons from Massachusetts on Long Term Rates for QFs”.

"Reviewing Utility Supply Plans," Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30 1985.

"Power Plant Performance," National Association of State Utility Consumer Advocates; Williamstown, Massachusetts, August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals; August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations; March 1988 to June 1989.

EXPERT TESTIMONY

1. **MEFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **MEFSC** 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **MEFSC** 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **ASLB, NRC** 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. **MDPU** 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. **MDPU** 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **MDPU** 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **MDPU** 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **MEFSC** 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16 1980.

Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **MDPU** 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas PUC** 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **MEFSC** 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **MDPU** 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **MDPU** 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26 1981 and February 13 1981.

    Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QFs in specific areas; wheeling; standardization of fees and charges.

17. **MEFSC** 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **MDPU** 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **MDPU** 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **DCPSC** FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **NHPUC** DE1-312; Public Service of New Hampshire-Supply and Demand; Conservation Law Foundation, et al.; October 8 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Illinois Commerce Commission** 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **New Mexico PSC** 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Connecticut Public Utility Control Authority** 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **MDPU** 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15 1983.

Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Connecticut Public Utility Control Authority** 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **MEFSC** 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Michigan PSC** U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **MDPU** 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **MDPU** 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Michigan PSC** U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **MDPU** 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Pennsylvania PUC** R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **NHPUC** 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November 1984.

    Profit margin calculations, including methodology and implementation.

40. **MDPU** 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11 1984.

Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14 1984.

    Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **MDPU** 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vermont PSB** 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **MDPU** 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25 1985, and October 18 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **MDPU** 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **New Mexico PSC** 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Pennsylvania PUC** R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14 1986.

    Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **MDPU** 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Pennsylvania PUC** R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **New Mexico PSC** 2004; Public Service of New Mexico, Palo Verde Issues; New Mexico Attorney General; May 7 1986.

    Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. **Illinois Commerce Commission** 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **New Mexico PSC** 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston, Public Improvements Commission;** Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18 1986.

    History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **MDPU** 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **New Mexico PSC** 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **MDPU** 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Massachusetts Division of Insurance** 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17 1987.

    STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. **Minnesota PUC** ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17 1987.

    Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Massachusetts Division of Insurance** 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **MDPU** 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4 1987.

    Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Massachusetts Division of Insurance** 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14 1987.

    Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Massachusetts Division of Insurance;** 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **MDPU** 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **MDPU** 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18 1988, and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **MDPU** 88-67; Boston Gas Company; Boston Housing Authority; June 17 1988.

    Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **Rhode Island PUC** Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Massachusetts Division of Insurance** 88-22; 1989 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vermont PSB** Docket No. 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vermont House of Representatives, Natural Resources Committee;** House Act 130; “Economic Analysis of Vermont Yankee Retirement”; Vermont Public Interest Research Group; February 21 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **MDPU** 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6 1989.

Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vermont PSB** Docket No. 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority; June 16 1989.

    Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **MDPU** 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30 1989.

    Prudence of BECo's decision of spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **MDPU** 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric; July 24 1989. Rebuttal, October 3 1989.

    Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **MDPU** 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13 1989.

    Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vermont PSB** 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **MDPU** 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December 1989; April 1990; May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC**; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Illinois Commerce Commission** Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Maryland PSC** Case No. 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18 1990.

Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Indiana Utility Regulatory Commission;** Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **MDPU** Dockets 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **MEFSC** 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** Docket No. 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Virginia State Corporation Commission** Case No. PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6 1991.

    Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **MDPU** Docket No. 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17 1991.

    Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration;** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech; May 13 1991.

    NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. **Vermont PSB** Docket No. 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19 1991.

    Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **South Carolina PSC** Docket No. 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13 1991. Surrebuttal October 2 1991.

    Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Maryland PSC** Case No. 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19 1991.

    Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport Planning Board;** AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1 1991.

    New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **MDPU** Docket No. 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4 1991. Rebuttal, December 13 1991.

    Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Florida PSC** Docket No. 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21 1991.

    Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Florida PSC** Docket No. 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31 1991.

    Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Pennsylvania PUC** Dockets I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **South Carolina PSC** Docket No. 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20 1992.

     Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **MDPU** Docket No. 92-92; Adequacy of Boston Edison's Street-Lighting Options; Town of Lexington; June 22 1992.

Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **South Carolina PSC** Docket No. 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4 1992.

Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **North Carolina Utilities Commission** Docket No. E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29 1992.

General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ontario Environmental Assessment Board** Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** Docket No. 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine Board of Environmental Protection;** In the Matter of the Basin Mills Hydroelectric Project Application; Conservation Intervenors; November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Maryland PSC** Case No. 8473; Review of the Power Sales Agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel; November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **North Carolina Utilities Commission** Docket No. E-100, Sub 64; Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina; Southern Environmental Law Center; November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **South Carolina PSC** Docket No. 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24 1992.

DSM planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Florida Department of Environmental Regulation** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation, December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Maryland PSC** Case No. 8487; Baltimore Gas and Electric Company, Electric Rate Case; January 13 1993. Rebuttal Testimony: February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Maryland PSC** Case No. 8179; for Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run; Maryland Office of People's Counsel; January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

112. A **Michigan PSC** Case No. U-10102; Detroit Edison Rate Case; Michigan United Conservation Clubs; February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

113. **Ohio PUC** Dockets No. 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati, City of Cincinnati, April 1993.

DSM planning, program designs, potential savings, and avoided costs.

114. **Michigan PSC** Case No. U-10335; Consumers Power Rate Case; Michigan United Conservation Clubs; October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

115. **Illinois Commerce Commission** 92-0268, Electric-Energy Plan for Commonwealth Edison; City of Chicago. Direct testimony, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

116. **FERC** Projects Nos. 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for Licensing of Hydro Power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

117. **Vermont PSB** Dockets No. 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching and DSM Program Design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

118. **Florida PSC** Dockets 930548-EG–930551–EG, Conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

119. **Vermont PSB** Docket No. 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

120. **MDPU** 94-49, Boston Edison integrated resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

121. **Michigan PSC** Case No. U-10554, Consumers Power Company DSM Program and Incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

122. **Michigan PSC** Case No. U-10702, Detroit Edison Company Cost Recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **New Jersey Board of Regulatory Commissioners** Docket No. EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

124. **Michigan PSC** Case No. U-10671, Detroit Edison Company DSM Programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

125. **Michigan PSC** Case No. U-10710, Power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **FERC** Projects Nos. 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

127. **North Carolina Utilities Commission** Docket No. E-100, Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

128. **New Orleans City Council** Docket No. UD-92-2A and -2B, Least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

129. **DCPSC** Formal Case No. 917, II, Prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

130. **Ontario Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

DSM cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

131. **New Orleans City Council** Docket No. CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

132. **MDPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

133. **Maryland PSC** Case No. 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995

Rate design, cost-of-service study, and revenue allocation.

134. **North Carolina Utilities Commission** Docket No. E-2, Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

135. **Arizona Commerce Commission** Docket No. U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

136. **Ohio PSC** Case No. 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

137 **Vermont PSB** Docket No. 5835; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

138. **Maryland PSC** Case No. 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

138 A. **MDPU** in Docket No. DPU 96-100; Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

139. **MDPU** in Docket No. DPU 96-70; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

140. **MDPU** Docket No. DPU 96-60; Massachusetts Attorney General. Direct testimony, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

141. **Maryland PSC** Case No. 8725; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

142. **New Hampshire PUC** Case No. DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

143. **Ontario Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

144. **New York PSC** Case 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

145. **Vermont PSB** Docket No. 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

146. **MDPU** Docket No. 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

147. **Vermont PSB** Docket No. 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

148. **MDPU** Docket No. 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

149. **MDTE** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

150. **NH PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

151. **Maryland PSC** Case No. 8774; APS-DQE merger; Maryland Office of People's Counsel. February, 1998.

Power-supply arrangements between APS's operating subsidiaries; power-supply savings; market power.

152. **Vermont PSB** Docket No. 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

153. **Maine PUC** Docket No. 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

154. **MDTE** Docket No. 98-89, purchase of Boston Edison municipal streetlighting, Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

155. **Vermont PSB** Docket No. 6107, Green Mountain Power rate increase, Vermont Department of Public Service. September 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

156. **MDTE** Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October, 1998. Joint surrebuttal with Jonathan Wallach, January, 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

157. **Maryland PSC** Case No. 8794 and 8804; BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December, 1998; rebuttal, March, 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

158. **Maryland PSC** Case No. 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

159. **Maryland PSC** Case No. 8797; Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March, 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Connecticut DPUC** Docket No. 99-02-05; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

161. **Connecticut DPUC** Docket No. 99-03-04; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

162. **Washington UTC** Docket No. UE-981627; PacifiCorp–Scottish Power Merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

163. **Utah PSC** Docket No. 98-2035-04; PacifiCorp–Scottish Power Merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

164. **Connecticut DPUC** Docket No. 99-03-35; United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

165. **Connecticut DPUC** Docket No. 99-03-36; Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; Supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

166. **W. Virginia PSC** Case No. 98-0452-E-GI; electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

167. **Ontario Energy Board** File No. RP-1999-0034; Ontario Performance-Based Rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

168. **Connecticut DPUC** Docket No. 99-08-01; standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; Supplemental January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

169. **Connecticut Superior Court** Docket No. CV 99-049-7239; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the CDPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

170. **Connecticut Superior Court** Docket No. CV 99-049-7597; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the CDPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

171. **Ontario Energy Board** File No. RP-1999-0044; Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

172. **Utah PSC** Docket No. 99-2035-03; PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

173. **Connecticut DPUC** Docket No. 99-09-12; Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January, 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

174. **Ontario Energy Board** File No. RP-1999-0017; Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

175. **NY PSC** Case No. 99-S-1621; Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

176. **Maine PUC** Docket No. 99-666; Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May, 2000; Surrebuttal, August, 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

177. **MEFSB** 97-4; MMWEC gas-pipeline proposal; Town of Wilbraham, Mass. June, 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

178. **Connecticut DPUC** 99-09-03; Connecticut Natural Gas Corporation Merger and Rate Plan; Connecticut office of Consumer Counsel. September, 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

179. Connecticut DPUC Docket No. 99-09-12RE01; Proposed Millstone Sale; Connecticut Office of Consumer Counsel. November, 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

180. MDTE Docket No. 01-25; Purchase of Streetlights from Commonwealth Electric; Cape Light Compact. January, 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

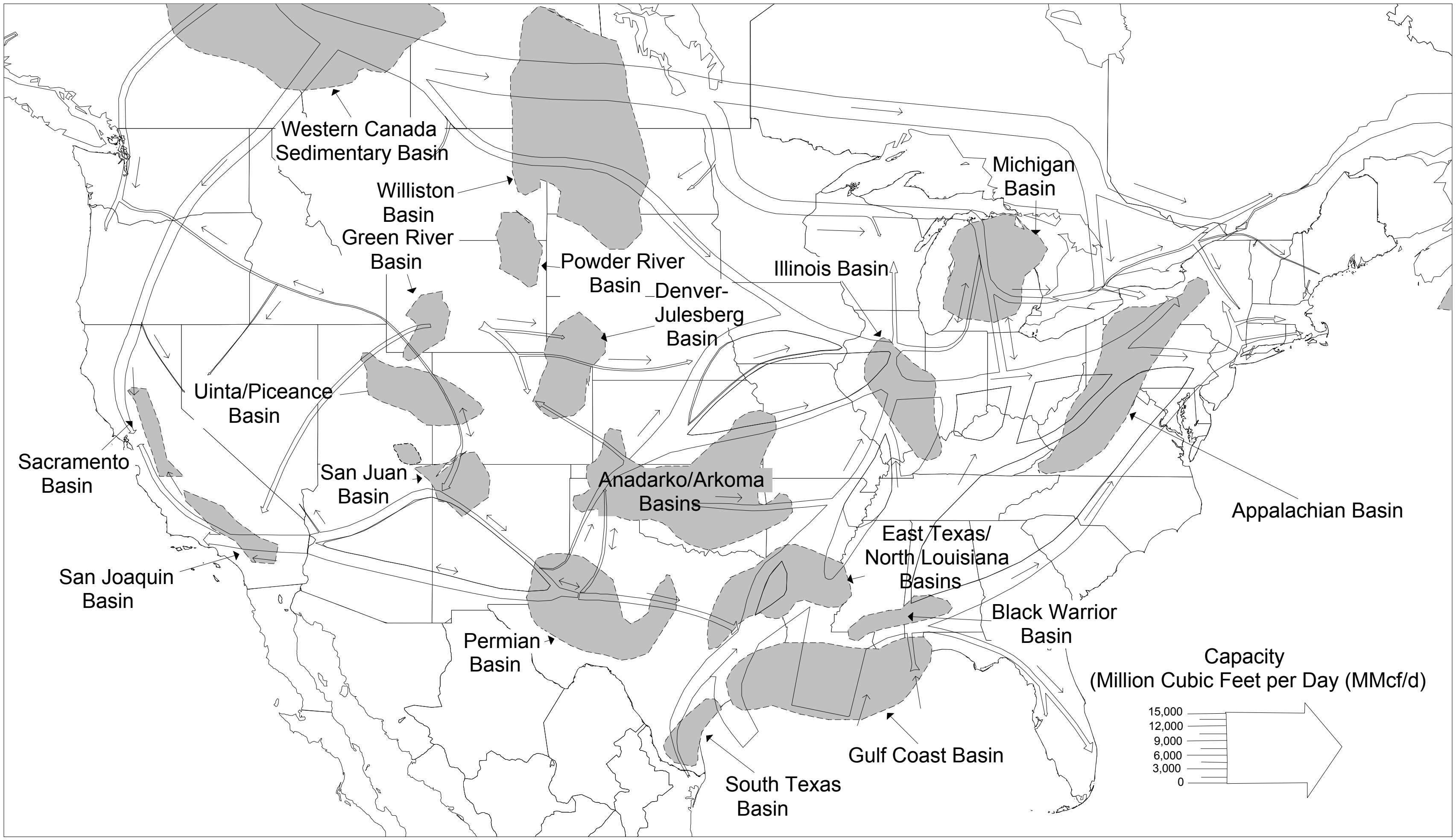
181. Connecticut DPUC Dockets Nos. 00-12-01 and 99-09-12RE03; Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March, 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

182. Vermont PSB Dockets Nos. 6460 & 6120; Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

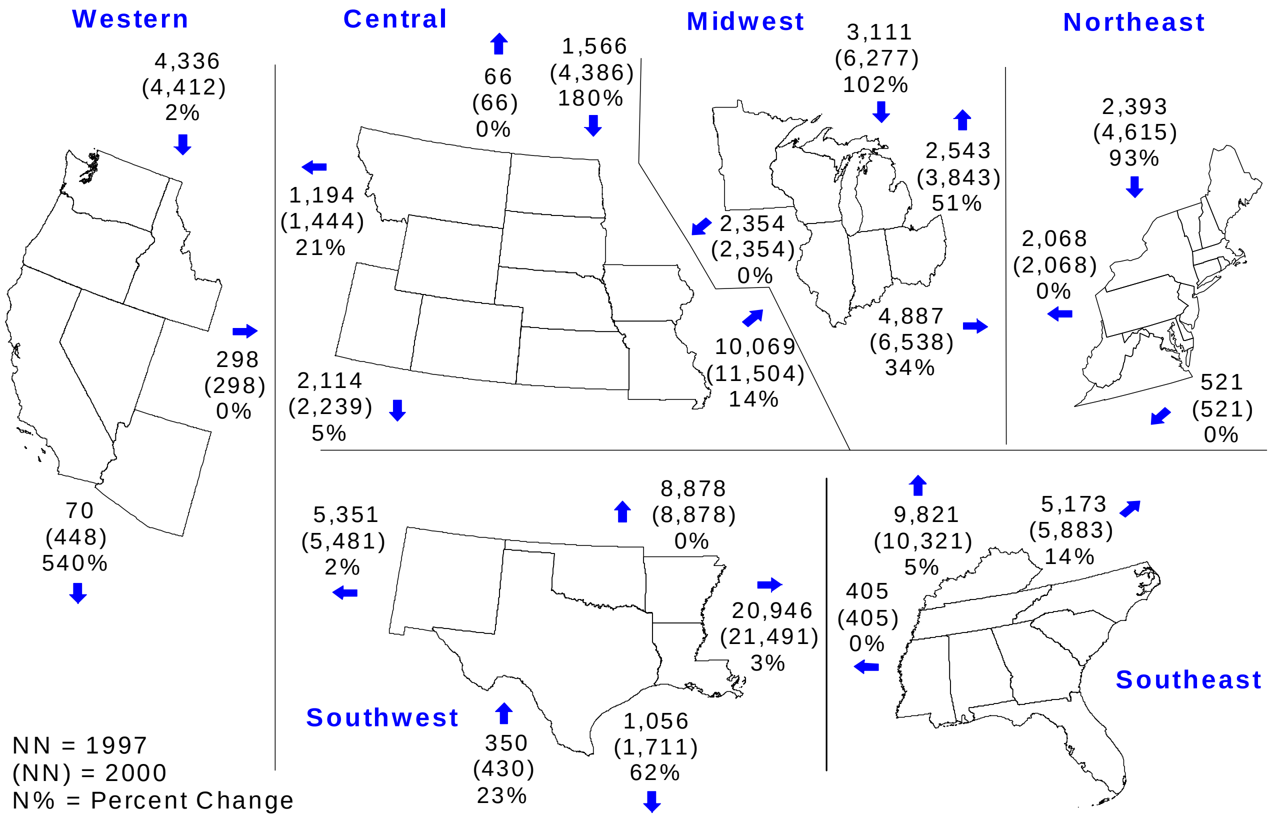
Review of power-planning decisions from early 1990s; Calculation of present damages from imprudence.

Schedule PLC-2:
Major Natural-Gas-Producing Basins and Associated Transportation Corridors



Alex, Aileen. 2001. "Risk of Infrastructure Failure in the Natural Gas Industry." Washington: U.S. EIA; unnumbered eighth page.

Schedule PLC-3:
Region-to-Region Natural-Gas Pipeline Capacity, 1997 and Proposed by 2000
(Volumes in Million Cubic Feet per Day)



Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System: Natural Gas Proposed Pipeline Construction Database, as of August 1998, and Natural Gas Pipeline State Border Capacity Database.

From “Natural Gas 1998: Issues and Trends.” DOE/EIA 0560-98. Washington: U.S. EIA.