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 $1.1 \times 0.75 = 82.5\%$.[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 down-stream 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?

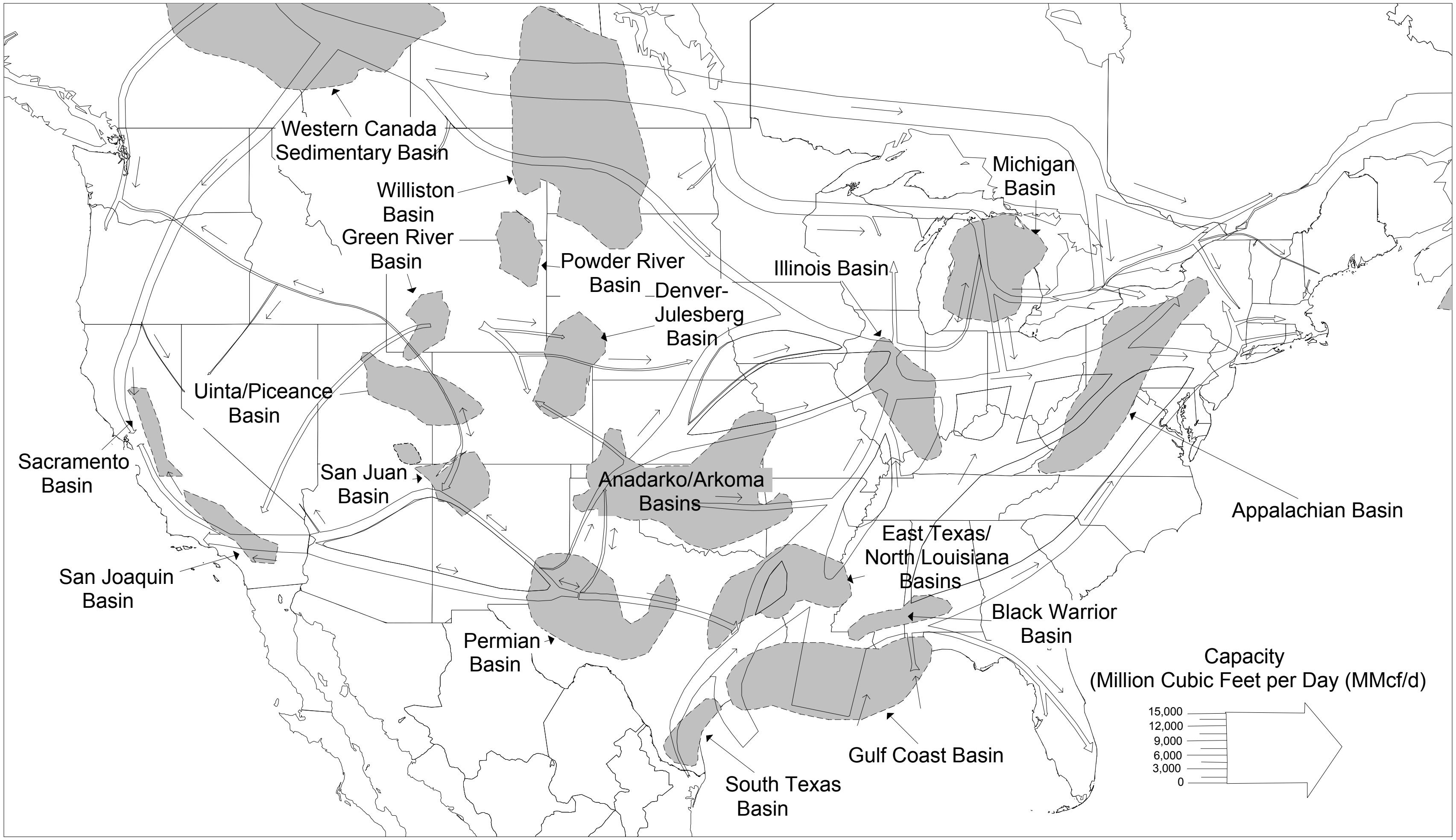
A: Yes. If the Board decides to implement those features of the Joint Position, Public Service can release capacity, provide incentives, and otherwise encourage development of a competitive market, without irrevocably relinquishing control over vital resources.

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?

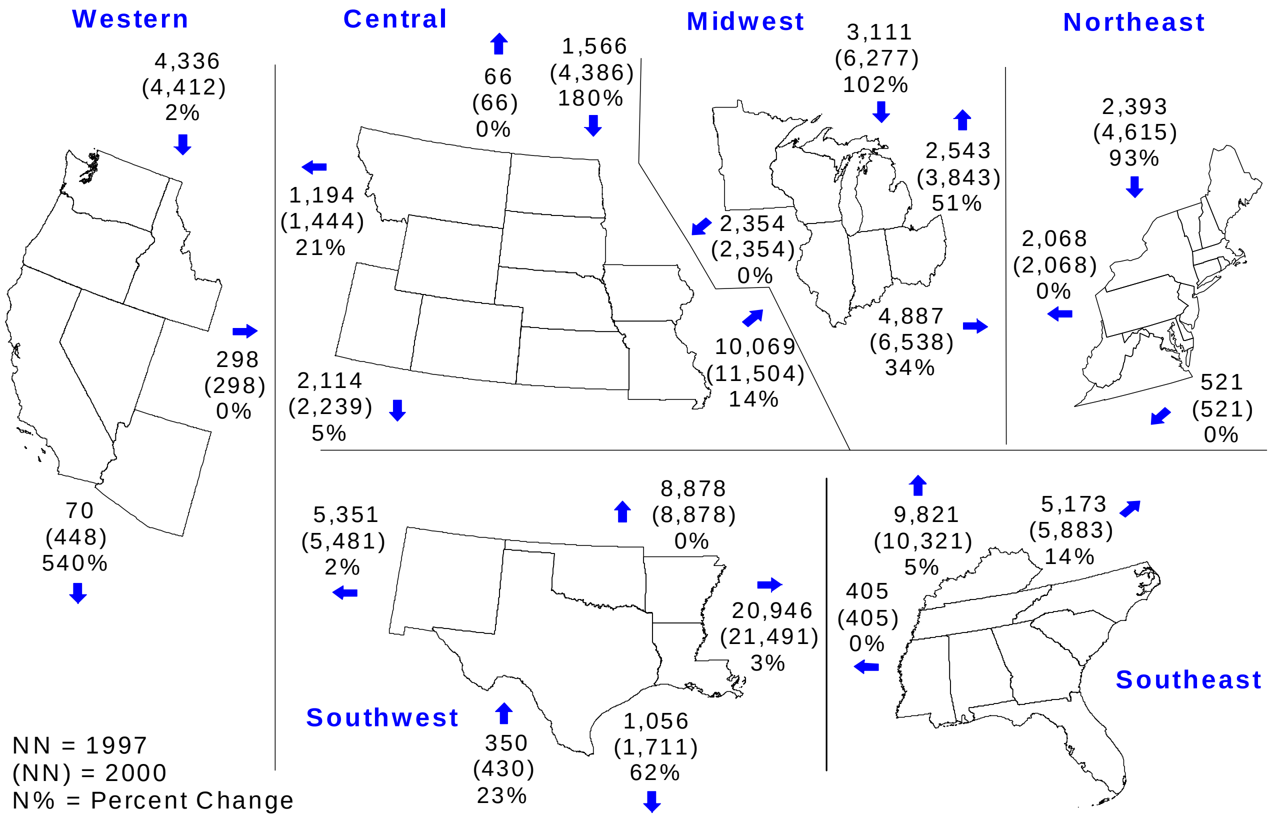
A: Yes.

Schedule PLC-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.