BEFORE THE STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW

I/M/O PUBLIC SERVICE ELECTRIC & GAS	)	
COMPANY S PROPOSAL TO TRANSFER	)	**BPU DOCKET NO. GR00080564**
ITS RIGHTS AND OBLIGATIONS UNDER	)	**OAL DOCKET NO. PUC-09734-OON**
ITS GAS SUPPLY AND CAPACITY	)	
CONTRACTS AND OPERATING	)	
AGREEMENTS TO AN UNREGULATED	)	
AFFILIATE AND FOR OTHER RELIEF	)	

DIRECT TESTIMONY OF RICHARD W. LELASH ON BEHALF OF THE NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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Filed: June 6, 2001

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DOCKET NO. GM00080564
TESTIMONY OF RICHARD W. LELASH

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I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Richard W. LeLash and my business address is 18 Seventy Acre Road, Redding, Connecticut.

Q. WHAT IS YOUR CURRENT BUSINESS AFFILIATION?

A. I am an independent financial and regulatory consultant working on behalf of several state public utility commissions and consumer advocates.

Q. PRIOR TO YOUR WORK AS AN INDEPENDENT CONSULTANT, WHAT WAS YOUR BUSINESS AFFILIATION, AND WHAT WAS YOUR REGULATORY EXPERIENCE?

A. I was a principal with the Georgetown Consulting Group for twenty years. During my affiliation with Georgetown, and continuing to date, I have testified on cost of service, rate of return, and regulatory policy issues in more than 230 regulatory proceedings. These testimonies were presented before the Philadelphia Gas Commission, the Federal Energy Regulatory Commission and in the following jurisdictions: Alabama, Arizona, Colorado, Delaware, District of Columbia, Georgia, Illinois, Kansas, Maine, Maryland, Minnesota, Missouri, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, U.S. Virgin Islands, and Vermont. Details concerning my recent testimonies are included in the Appendix section of this testimony.

Q. PRIOR TO JOINING GEORGETOWN, WHAT WAS YOUR BUSINESS EXPERIENCE?

A. For approximately five years I was employed by PepsiCo, Inc. in a series of positions. I began work as a Senior Business Planner on the corporate staff and then transferred to the Pepsi-Cola Company where I was Manager of Financial Services and later Director of Financial Services. I also served as Director of Financial Planning and Analysis for the Pepsi-Cola Bottling Group and as Vice-President of Finance for the Pepsi-Cola Equipment Corp.

My positions in finance with various Pepsi-Cola operations involved capital expenditure evaluation and budgeting, financial analysis, profit planning, financial reporting, and strategic planning. As Vice-President of Finance, I was responsible for all financial operations of the Pepsi-Cola Equipment Corp., a subsidiary of PepsiCo.

Prior to my work at PepsiCo, I was employed by Touche Ross & Co. in its Management Services Division. While at Touche Ross & Co. I was a Project Manager and worked on a broad range of consulting engagements. In addition to general financial and accounting engagements, I was involved to a considerable degree in utility regulation.

Q. COULD YOU SUMMARIZE SOME OF YOUR REGULATORY WORK WHILE AT TOUCHE ROSS?

A. While with Touche Ross, I analyzed utility filings and assisted in preparing testimony in approximately twelve state jurisdictions. I also worked for five city regulatory authorities, the Civil Aeronautics Board, and the Federal Communications Commission. In total, I was involved in about 40 rate investigations involving water, electric, bus transit, sewer, gas, telephone, airline, and cable utilities. My work involved rate of return, accounting, and tariff design for the majority of these utility groups.

Q. MR. LELASH, WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I graduated in 1967 from the Wharton School with a BS in Economics and in 1969 from the Wharton Graduate School with an MBA.

Q. HAVE YOU WORKED WITH ANY PROFESSIONAL GROUPS OR ORGANIZATIONS?

A. Yes. During the past thirty years I have been a member of and have worked with various professional and trade organizations. I have conducted lectures and seminars involving economic, financial, regulatory, and accounting topics such as return on investment, cash forecasting, planning, cost accounting, project and cost control, and accounting systems. Additionally, I serve as the President and Trustee of a private foundation where my responsibilities include managing the foundation's overall operations.

Q. DURING THE COURSE OF YOUR REGULATORY WORK, WHAT HAS BEEN YOUR EXPERIENCE WITH GAS POLICY AND PROCUREMENT?

A. Since 1980, I have worked extensively on gas policy and procurement issues. In my Appendix there is a listing of the recent cases in which I have sponsored testimony. In addition to these cases, I have reviewed and analyzed many other gas policy filings which were resolved through stipulation. Among other issues, my testimonies have involved gas service unbundling, physical and economic bypass, gas supply incentives, gas plant remediation costs, gas price hedging, demand and capacity planning, gas storage options, gas price forecasting, and least cost gas standards. In addressing these issues, I have analyzed gas regulatory filings involving about 30 different local distribution companies. During the past few years, I have worked on restructuring and unbundling matters for regulatory commissions or their staffs in Georgia, Delaware, and Rhode Island and for consumer advocates in New Jersey and Pennsylvania.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WOULD YOU PLEASE STATE THE SCOPE AND PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was hired by the New Jersey Division of the Ratepayer Advocate ("Ratepayer Advocate") to review the proposal filed by Public Service Electric and Gas Company ("Public Service" or "Company"). My review and analysis evaluated the Company's proposal with respect to its impact on ratepayers and in the context of established regulatory standards.

The purpose of my testimony is to present findings and recommendations to the New Jersey Board of Public Utilities ("Board") concerning issues raised by the Company. The filing seeks to allow Public Service's parent company, Public Service Enterprise Group ("PSEG") to create an affiliate ("Affiliate") which will receive Public Service's gas supply contracts and enter into a sole-source Requirements Contract to provide natural gas supply and balancing services to Public Service for all of the Company's Basic Gas Supply Service ("BGSS") and other customers.

In August 2000, the Company filed an initial proposal concerning the contract transfer and the Requirements Contract ("initial proposal") which was subsequently superseded by a Stipulation of Settlement signed by some of the parties ("Joint Position"), which was filed on April 16, 2001, and modified in an Addendum submitted on May 21, 2001. This testimony addresses the proposed transactions as specified in the amended Joint Position.

I note that the Company's proposal may be subject to further substantial changes. The Company's April 21, 2001 Addendum included substantial modifications to what had been characterized as a final proposal. It is unknown whether the Company intends to make further modifications. In response to a Ratepayer Advocate discovery request (RAR-T-56), the Company has submitted two sets of revisions to the Requirements Contract. These revisions (one dated May 14 and the second dated May 30) contain substantial changes and additional terms and conditions. The latest version contains significant revisions concerning the operation and use of the Company's peak shaving facilities and provisions for arbitration which would further preempt the already limited regulatory authority provided for the Board under Company's proposal. It is unclear whether or not the Company considers the May 30 draft the final version. As a result of these and other deficiencies in the Company's submissions, substantial areas of uncertainty remain as to exactly what is being proposed.

Another Ratepayer Advocate witness, Mr. Paul Chernick, will be addressing the overall implications of the Company's proposal on New Jersey's energy markets and on the potential structure of BGSS. Mr. Chernick will also present a critique of the valuation testimony presented by Company witness Jeffery Makholm. My testimony will address the impact of the Public Service's proposal on the pricing and other regulatory protections currently afforded the Company's firm ratepayers and its compliance with the policies and mandates of the Electric Discount and Energy Competition Act ("EDECA"), as I understand them. I will also provide recommendations as to the measures the Board can take to encourage the development of competitive options for natural gas consumers, while maintaining important consumer protections mandated by EDECA.

Q. IN PERFORMING YOUR REVIEW AND ANALYSIS, WHAT DATA SOURCES DID YOU UTILIZE?

A. My review and analysis encompassed the Company's filings, responses to discovery requests, and information provided during discovery meetings. I also utilized information provided in previous Company proceedings before the Board and general interpretations of the requirements of EDECA based on discussions with counsel.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, it was.

III. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. BASED ON YOUR INVESTIGATION, WHAT ARE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE COMPANY'S CONTRACT TRANSFER AND REQUIREMENTS CONTRACT?

A. Based on my review and analysis, the Company's proposal is both contrary to the policies of EDECA and detrimental to consumers, for the following reasons:

1. The proposed transfer of Public Service's transportation and storage capacity contracts ("contract transfer") and the establishment of a full requirements contract ("Requirements Contract") between Public Service and its Affiliate is fundamentally at odds with the mandates of EDECA for the structure and pricing of BGSS. Under EDECA, consumers are entitled to fully regulated BGSS as a backstop against the exercise of market power in a natural gas marketplace that is not yet fully competitive. The Company's proposal would violate EDECA and place essential gas supply resources in the hands of an unregulated monopoly, which would effectively eliminate the Board's ability to assure reliable, reasonably priced gas supplies for BGSS customers.

2. EDECA specifically provides that BGSS must be provided by the utilities at cost-based rates until at least December 31, 2002. Thereafter, if the Board determines that utility-provided BGSS is no longer in the public interest, BGSS can be provided by

non-utility suppliers based on actual costs or the results of a competitive bidding process directed by the Board. Under the Public Service proposal, Industrial and Commercial ("I&C") customers, and later residential customers, would be provided with BGSS at essentially unregulated prices, based on neither actual costs nor the results of competitive bidding. Further, the minimum prices proposed to be charged to BGSS customers incorporate unjustified and improperly noticed rate increases. BGSS customers would lose the benefits of storage, hedging, and margin revenues that are currently flowed back to ratepayers.

3. The Affiliate would gain opportunities to earn windfall profits, using resources developed over the years at ratepayer expense.

4. Contrary to the Company's statements, the Board cannot rely upon the competitive market to protect consumers against unreasonable prices. At present, competitive options are very limited for smaller natural gas customers. The Joint Position includes a number of measures to promote competition, but there are no guarantees that they will produce and maintain a robust competitive market, especially as these measures are phased out over the next few years.

5. The proposal would be, for all practical purposes, irreversible. The Board would have no practical ability to transfer the procurement function back to the utility operation,

as the resources needed to provide BGSS would have been irrevocably transferred to the Affiliate and third-party suppliers ("TPSs").

6. The Company's proposal unreasonably discriminates against market participants other than the Affiliate, in apparent violation of the Board's Interim Affiliate Relations Standards.

7. The measures proposed in the Joint Position to promote the development of a competitive market can all be implemented without the proposed contract transfer and Requirements Contract. Having the Company, rather than the Affiliate, promote competition has the advantage of maintaining price protection for consumers, while a competitive market develops, and retaining the Board's ability to implement additional measures, if needed, beyond those specified in the Joint Position.

For these reasons, as well as those discussed in Mr. Chernick's testimony, I recommend as follows:

1. The Board should reject the proposed contract transfer and Requirements Contract. The Board should specifically find that these proposed transactions are in violation of EDECA and imprudent with respect to gas supply procurement.

2. Public Service should be directed to implement measures to encourage competition while it retains control of its essential natural gas supply resources. These measures could include capacity release programs, economic incentives, and a BGSS pilot program such as those proposed as part of the Joint Position.

3. A transfer should be considered only after a robust competitive natural gas marketplace has developed, and the Board is assured that Public Service's control of its gas supply resources is no longer needed to assure reliable and reasonably priced BGSS, otherwise consumers will be serviced by an "unregulated monopoly."

4. In order to avoid an undue preference to PSEG and its affiliates, and to assure that ratepayers receive the full value of any transferred resources, any transfer should be subject to competitive bidding.

IV. ANALYSIS OF COMPANY'S PROPOSAL

A. THE COMPANY'S PROPOSAL WOULD SEVERELY COMPROMISE THE BOARD'S ABILITY TO ASSURE RELIABLE AND REASONABLY PRICED BGSS SERVICE.

Q. HOW WOULD THE PUBLIC SERVICE PROPOSAL AFFECT EDECA'S POLICIES AS THEY RELATE TO THE BOARD'S REGULATORY AUTHORITY OVER BGSS?

A. The definition of BGSS contained in Section 3 of EDECA states that BGSS is to be "fully regulated by the Board." Thus, EDECA contemplates that, until a robust competitive market develops, ratepayers will be assured of an affordable regulated BGSS supply as a "backstop" against the exercise of market power. The Company's proposal would violate this fundamental EDECA policy. Currently, the Board exercises the full scope of its regulatory authority over the natural gas utilities' procurement activities and pricing, to assure reliable, reasonably priced gas supplies for BGSS customers. The Public Service proposal would severely compromise the Board's ability to perform this function, by placing the procurement and management of gas supply resources, as well as pricing decisions, within the discretion of an unregulated entity.

Q. WOULD YOU PLEASE EXPLAIN BRIEFLY HOW THE BOARD CURRENTLY OVERSEES THE PROCUREMENT AND MANAGEMENT OF GAS SUPPLY RESOURCES FOR BGSS CUSTOMERS?

A. New Jersey's gas utilities provide natural gas to their BGSS consumers using a variety of resources, tariffs, and contractual arrangements. These include the following:

- Natural gas produced in the Gulf Coast region and in Canada.
- Storage services provided by the interstate pipelines at facilities located in the producing regions and in western Pennsylvania and Ohio.
- Interstate pipeline transportation services, used to transport the gas from the producing areas to the storage facilities and to delivery points in New Jersey.
- Peaking supplies, such as those provided by Public Service's liquefied natural gas ("LNG") and propane ("LPG") facilities.
- Exercise of rights to interrupt service to customers supplied by the Company under tariffs or contractual arrangements providing the Company with interruption rights.
- Contractual provisions, such as Public Service's arrangements with non-utility generators and its electric generation affiliate, which provide the right to recall gas supplies under certain conditions.

The Board currently reviews the utilities' procurement strategies and activities, as well as their operation and management of their gas supply resources, as part of the utilities' annual gas cost adjustment proceedings and through audits. From time to time the Board also exercises its authority to investigate the utilities' gas supply related activities. An example is the Board's currently ongoing investigations of all four utilities' interruption practices.

Q. WHAT WOULD BE THE EFFECT OF THE COMPANY'S PROPOSAL ON THE BOARD'S OVERSIGHT OF BGSS PROCUREMENT ACTIVITIES?

A. As proposed by the Company, the Board's authority would be virtually eliminated. The Company's response to Request RAR-T-8 states that procurement decisions would be completely within the Affiliate's discretion. As explained by Company witness David Wohlfarth, the Affiliate would be subject to a contractual obligation to provide gas supplies for the Company's BGSS service, but the Company is proposing that the Board have no jurisdiction to monitor the Affiliate's procurement strategies or activities (Tr. 235).

This is a particular concern because the Affiliate, as an unregulated entity, could well decide to pursue market opportunities well beyond the current scope of the utility's operation. The Company has acknowledged in Response RAR-T-8 that the Affiliate could decide to enter into new gas supply arrangements for the purpose of serving other customers. Thus far, the Company has declined to provide the Board with information about the expected scope of the Affiliate's activities. It is entirely possible that the Affiliate could reconfigure its gas supply portfolio to match the Affiliate's requirements rather than the Company's BGSS demand portfolio, with unknown impacts on the quality and cost of the service provided.

Q. CAN YOU PROVIDE ANY EXAMPLES?

A. Based on the proposed Addendum to Paragraph 12 of the Joint Position, which apparently was negotiated to induce large cogenerators to sign the Joint Position, it appears that the Company may have already committed to managing its portfolio to benefit special interests. The Addendum includes a provision that "the Affiliate, in its sole discretion, may restructure, renegotiate, or terminate any contract in Schedule 1 if it deems it in the best interest of its BGSS and contract cogeneration customers." Pursuant to the revised Paragraph 12 the gas cogeneration contracts are to remain unaffected by the Board's approval of the Stipulation, but somehow they will become determinants in what capacity will be held by the Affiliate, possibly to facilitate their access to surplus capacity on a "most favored nation" basis.

Q. WOULD THERE BE ANY IMPACT ON THE BOARD'S OVERSIGHT OF THE OPERATION AND MANAGEMENT OF THE GAS SUPPLY RESOURCES USED TO PROVIDE BGSS?

A. This aspect of the Board's authority also would be virtually eliminated. After the transfer, the Board would lose its authority to directly control how the contracts are used. The Affiliate, which would control the contracts, would have only a contractual obligation to use its transportation and storage rights to supply BGSS customers. According to Company witness David Wohlfarth, the Company would have to "obtain capacity in the market" to supply its BGSS customers (Tr. 231). According to a discovery response (RAR-T-21), the Affiliate would be liable for "direct damages" in the event of default. However, the scope of this remedy is unclear. At the hearings Company witness David Wohlfarth was unable to state what types of damages would be recoverable from the Affiliate in the event of a default (Tr. 271-273). Mr. Wohlfarth also acknowledged that the Requirements Contract contains no provisions for penalties in the event of a failure to deliver (Tr. 273). Further, it should be noted that damages and penalties would represent a transfer of funds between affiliate entities. Under the Company's proposed Market Price Gas Service ("MPGS") pricing mechanism, there does not appear to be any provision to assure that customers would benefit from such payments.

Of even greater importance, contractual rights to damages and penalties may not be adequate to assure reliable service. The State's gas consumers receive most of their natural gas from the limited resources provided by the interstate pipelines. Under certain circumstances, the pipeline resources may not even be sufficient to fulfill design day requirements. New Jersey lacks the geological formations that can be used for large-scale natural gas storage, and its supplemental gas supplies, such as LNG and LPG, are quite limited. The Company appears to recognize its dependence on access to the interstate pipeline resources as part of its proposed capacity release programs for TPSs. These programs are subject to the reservation of recall rights in the event a TPS fails to deliver necessary volumes. As explained by Company witness David Wohlfarth, recall rights are required because the capacity is needed to provide BGSS service, and therefore even "stiff penalties" will not be adequate (Tr. 216-217).

Company witness David Wohlfarth has testified that the Company would be willing to modify its proposal to provide Public Service with recall rights (Tr. 231, 271). However, this does not appear to be a part of the Company's current proposal. In its latest version of the Requirements Contract, such reliability issues are really not resolved. The Company's May 30, 2001 draft of the Requirements Contract includes a proposed new Article 13 which provides Public Service with the right to terminate the contract and reacquire its contracts in the event of a default. However, new section 1.8 defines a default as a failure by the Affiliate to meet its obligations on three days during any twelve month period. A provision which allows inadequate supplies for two days each year hardly guarantees "utility" quality supply reliability from the Affiliate. Further, Article 13 does not specify what happens to capacity assigned to TPSs, and in section 13.4 the Affiliate has reserved its rights to challenge the return of the capacity contracts to Public Service.

Q. WOULD THE PROPOSED TRANSACTIONS AFFECT THE BOARD'S ABILITY TO OVERSEE ANY GAS SUPPLY RESOURCES WHICH ARE NOT TO BE TRANSFERRED TO THE AFFILIATE?

A. This aspect of the Board's authority also would be affected. The Company is proposing to retain its peak shaving facilities, as well as its rights to interrupt service to customers supplied under tariffs or contractual arrangements which include interruption rights. However, the current draft of the proposed Requirements Contract appears to give the Affiliate absolute authority to direct the use of these important gas supply resources. Section 2.5 of the current (May 31, 2001) version of the Requirements Contract would require the Company to follow the Affiliate's instructions with respect to "Scheduling Coordination Services concerning matters that are within Buyer's [Public Service's] custody or control." Such Coordination Services include load scheduling, load balancing, curtailment or interruption, and capacity recall (section 1.18; Tr. 196). Section 8.1 would further require the Company to supply all gas ordered by the Affiliate from the peak shaving facilities, up to the maximum daily volumes these facilities can produce.

Decisions relating to the use of these resources can have significant impact on the quality and cost of service. Suppose, for example, the Affiliate were to decide to use peaking supplies to serve BGSS customers on a non-peak day so that it could make off-system sales from flowing gas supplies. The high-cost peaking supplies would be reflected in the BGSS price, while the Affiliate would retain the margins generated by the off-system sales. The Affiliate presumably could direct the Company to use the peaking supplies, even though this might jeopardize system reliability later in the season. The Company has stated in a discovery response (INF-T-7) that the details of its operation of the peaking facilities are to be addressed in an "agency agreement" that will be prepared only after the "satisfactory resolution of this proceeding." The Company apparently intends to prepare this agreement with no Board oversight or approval.

The Affiliate's proposed authority to direct the Company's exercises of interruption and recall rights raises similar concerns. The Affiliate could direct the Company to exercise these rights for economic reasons, such as to facilitate off-system sales, rather than operational considerations. The Company has claimed that it will determine when applicable customers should be interrupted (Company Response to INF-T-9). However, this is not reflected in the Company's current proposal which, as noted, includes interruption decisions in the definition of Scheduling Coordination Services which must be performed at the Affiliate's direction. It is also unclear how, as a practical matter, the Company would make such determinations. Interruptions, for the most part, are dictated by operational requirements, and since the Affiliate would be operating the gas supply portfolio, it is unclear how Public Service would know when interruptions were required. The Affiliate's portfolio management could be affected by many factors unrelated to Public Service's utility operations, such as the Affiliate's contractual commitments to other customers, and its desire to pursue off-system sales.

Q. ARE THERE ANY OTHER PROVISIONS THAT COULD AFFECT THE BOARD'S OVERSIGHT OF GAS SUPPLY MANAGEMENT AND SYSTEM OPERATION?

A. Yes. The Requirements Contract also contains provisions which unreasonably exempt the Affiliate from certain aspects of its obligation to supply natural gas to Public Service. For example, section 5.1 provides that the Affiliate "shall not be responsible for any deficiencies in the quality of natural gas delivered." This would appear to exempt the Affiliate from supply liability when it is the entity that controls both capacity and gas supply contracts. Likewise, section 8.1, which appeared for the first time in the May 30, 2001 version of the Requirements Contract, would obligate Public Service to deliver up to the "nameplate daily maximum volume of gas which can be produced by the Peak Shaving Facilities." This would appear to place an excessive performance requirement on the Company, as facilities of this type are frequently unable to attain their nameplate capacity. Both of these provisions appear to unreasonably favor the Affiliate to the detriment of the Company. With approval of the Requirements Contract as proposed, the Board could lose its ability to remedy these and other unreasonable allocations of risks.

Q. IF PROBLEMS WERE TO DEVELOP WITH THE PROPOSED ARRANGEMENTS FOR BGSS SUPPLY, WOULD THE BOARD HAVE THE AUTHORITY TO PLACE THE PROCUREMENT FUNCTION BACK WITH THE UTILITY?

A. The Board would have only limited ability to do so. The Requirements Contract, once approved, would give the Affiliate the exclusive right to provide all of the gas supply necessary to meet Public Service's BGSS obligations. The Board could presumably direct the Company not to renew the contract for a second term, but resumption of the procurement function by the utility at that time could well be a practical impossibility. The Affiliate would then have the right, though not the obligation, to return up to 50 percent of the transferred contracts. Thus, Public Service could have only 50 percent of its former gas supply portfolio.

Further, under sections 1.19 and 3.2 of the current version of the Requirements Contract, returned capacity contracts would represent a 50 percent undivided interest in the originally transferred contracts, amendments and supplements, and replacement contracts obtained by the Affiliate. Since procurement decisions would have been within the Affiliate's discretion during the initial term of the Requirements Contracts, the returned contracts could have been reconfigured to match the Affiliate's requirements rather than the Company's BGSS demand profile. It is also unclear what would happen to capacity which had been assigned to TPSs. Would such assigned capacity be returned to the Company or would the TPSs have the right to keep such capacity under their agreements with the Affiliate? In addition, all of the Company's gas supply personnel would be working for the Affiliate and thus, the Company would lack adequate staffing for gas supply planning, procurement and trading.

If Public Service were to exercise its right to renew the Requirements Contract for an additional three-year term, the mismatch at the end of the renewal term would only be more pronounced. Public Service would not have any of its gas supply portfolio returned, and its former gas supply personnel would remain with the Affiliate. If the Board, at that time, were to require the Company to have default responsibility for BGSS, or any other supplier of last resort ("SOLR") obligations, the Company would lack the supply resources to meet those obligations. The effect of this potential supply and demand mismatch is either to preempt the Board's authority over prospective BGSS offerings, or leave the Company with BGSS obligations without any gas supply resources. If sufficient TPSs were not then active in the market, Public Service ratepayers would effectively be captive to the Affiliate's non-regulated gas supply.

B. THE PROPOSAL IS IN CONFLICT WITH EDECA'S MANDATES FOR BGSS PRICING

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Q. TURNING TO PRICING, WOULD THE COMPANY'S PROPOSAL COMPLY WITH EDECA'S POLICIES CONCERNING THE PRICING OF BGSS?

A. Sections 10(r), through 10(u) of EDECA contain the following mandates as to the pricing of BGSS.

- Until at least December 31, 2002, and thereafter until the Board finds that utility-provided BGSS is no longer in the public interest, BGSS is to be provided by each utility, at Board-regulated prices based on actual costs of procurement.
- With the appropriate findings, the Board may permit non-utility suppliers to provide BGSS after December 31, 2002. However, BGSS would remain a fully regulated

service, to be provided at prices based on either actual procurement costs or the results of a competitive bidding process directed by the Board.

The Public Service proposal would violate these provisions, by essentially eliminating the Board's regulation of BGSS pricing, which, as noted, is required to be provided at cost through December 31. 2002 and thereafter until the Board finds this is no longer in the public interest. BGSS for I&C customers, and later residential customers, would be provided at prices determined largely within the discretion of the Affiliate. These prices would not be fully regulated by the Board, and they would be based neither on the actual costs of procurement, as required by EDECA through at least December 31, 2002, nor on the results of competitive bidding, as permitted upon appropriate Board findings after that date. BGSS customers would be denied the protection of regulated prices, with no guarantee that the competitive market would provide equivalent service and pricing.

Q. WOULD YOU PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES IN PRICING FOR BGSS CUSTOMERS?

A. Currently, the Company's residential customers are provided with BGSS service at a levelized rate, which is subject to reconciliation for over and under recoveries on an annual basis. (This pricing mechanism was modified to phase in recovery of the sharp increase in wholesale natural gas prices that occurred during the 2000-2001 winter season.) I&C customers' rates are set based on monthly market indexes, but subject to reconciliation for the Company's actual procurement costs. Therefore, if their actual gas costs are lower than the index rate, because of credits, storage transactions, or price hedging, they receive a credit through the monthly reconciliation mechanism. Thus, the I&C customers also receive cost-based rather than market-priced gas supplies. According to Company witness David Wohlfarth, this mechanism has worked well to track the Company's actual costs of procuring gas for these customers (Tr. 297).

The Company is proposing to replace the current cost-based tariffs with a mechanism based on the Company's MPGS rate schedules, which currently apply to a limited number of I&C customers that have returned to the Company's commodity service after a period of service from a TPS. The Company's initial proposal included an immediate transition to MPGS pricing for all BGSS customers. As part of the Joint Position, the Company is now proposing to retain the current levelized pricing for residential customers until April 1, 2004, at which time they too would be moved to market-based pricing. The proposed new pricing can be summarized as follows:

S The Affiliate would be provided with unlimited discretion to select a price each month between a floor and a ceiling, both of which would vary with market conditions.

S Through December 31, 2004, the floor rate would be based on a specified fixed rate component reflecting the cost of interstate transportation and storage capacity ("Non-Gulf Coast Cost"), plus a commodity component ("Gulf Coast Cost") based on short-term market indexes. The ceiling would be equivalent to the Company's Emergency Sales Service rate, which reflects the highest cost of gas purchased or used during the month, plus an adder of $1.81 per dekatherm.

- After December 31, 2004, the capacity component of both the floor and ceiling rates would be market-priced.[1]

Q. WILL THE PROPOSED PRICING MECHANISM RESULT IN REGULATED BGSS RATES?

A. For all practical purposes, the proposed pricing mechanism would result in unregulated BGSS rates. The Affiliate would have unlimited discretion to select MPGS rates at any level between the floor and ceiling rates; neither Public Service nor the Board would have any ability to review or challenge any rate within that range (Tr. 327, 340-341). With ceilings rates based on Emergency Sales Service rates which will exceed actual costs by a considerable margin, the only constraint on the Affiliates' rate decisions is more likely to be market forces rather than regulation (Tr. 471-472). Thus, the proposed pricing mechanism would not achieve EDECA's objective of providing customers with a backstop against unreasonable prices until a robust competitive market exists in New Jersey.

Q. WHAT RATES COULD BGSS CUSTOMERS EXPECT TO PAY UNDER THE PROPOSED PRICING MECHANISM?

A. It is impossible to predict what pricing policies the Affiliate will follow for BGSS supplies. However, the range of prices that could result can be illustrated by Public Service's commodity rates over the past several months. The proposed market pricing mechanism for

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[1] As discussed below, the Company has stated that it actually intends a cost-based rate to be adjusted annually, but the Joint Position has not been modified to reflect this.

BGSS customers is based on Public Service's current MPGS tariffs, which apply to a limited number of I&C customers who have returned to the Company's commodity service after receiving service from a TPS. As shown on Schedule 1, the MPGS rates for General Service ("GS") have been consistently higher than the corresponding cost-based "CS-GS" rates. Over the past 12 months, the differential has ranged from $0.26 to $0.70 per dekatherm. Further, the Company's ceiling rates for its MPGS rates, also shown on Schedule 1, are even higher, sometimes by a considerable margin. During the past 12 months, the ceiling rates for MPGS-CS customers exceeded the cost-based rates by as much as $2.96 per dekatherm. To date, the Company has followed a practice of setting MPGS rates at $0.26 to $0.27 per dekatherm over the floor rate, though, as shown on Schedule 2, the differential has been as high as $1.84 per dekatherm, as occurred in February, 2001. (For a typical 200-therm residential heating bill, this would have amounted to a differential of about $37.) There is no guarantee that this would continue if pricing decisions were vested in a non-regulated entity which is not accountable to the Board for its pricing decisions.

Q. IS THE COMPANY PROPOSING ANY OTHER RATE CHANGES?

A. Yes. As part of the Joint Position, the Company is seeking to include two improper rate increases in both the floor and ceiling rates described above. First, the Company is proposing to increase the Non-Gulf Coast Cost from the originally proposed $1.05 to $1.26 per dekatherm. Of the proposed 21 cent increase, 16 cents represents asserted increases in pipeline rates. This increase has been neither noticed to customers nor subjected to review by the Ratepayer Advocate and the Board. The remaining 5 cents is a wholly improper weather normalization adjustment. In its calculation of a per dekatherm rate to recover fixed costs under the Company's pipeline transportation and storage contracts, the Company divides the total fixed costs by the weather-normalized usage of the relevant customer classes. The Company historically has made its weather normalization adjustment using 30-year average temperatures. The Company is now proposing to use a 5-year average, which over-weights the recent warmer-than-normal winters. The Company does not claim to have Board approval for this change, which unreasonably overstates the per dekatherm charges required to recover fixed costs.

The Company is also proposing to increase the Gulf Coast Cost by 8 cents per dekatherm to reflect increases in the Company's carrying costs on gas in inventory. I know of no Board Order that would authorize the Company to make annual adjustments to this base rate expense item.

Q. WOULD BGSS CUSTOMERS LOSE ANY SPECIFIC BENEFITS THEY ARE CURRENTLY RECEIVING?

A. They would lose several important benefits of the existing cost-based pricing. Even at the specified floor prices, ratepayers would lose the benefits of storage transactions and gas price hedging. It is ironic that prior to the filing of the contract transfer proposal, the Company readily acknowledged the benefit of storage transactions and gas price hedging. In its July 1998 Levelized Gas Adjustment Clause ("LGAC") filing it stated that it would continue to hedge supplies up to its risk management program limits in order to stabilize its residential cost of gas. Indeed, in its March 30, 2001 Order in Docket No. GR00070491, the Board specifically directed the Company to submit a comprehensive hedging program in order to address the need for adequate programs "to protect ratepayers against the risk of future sharp fluctuations in wholesale natural gas prices" (Board Order, page 5). In light of this Order, and the Board's actions in the Provisional Rate Proceedings, it is difficult to understand why the Company believes that it is appropriate to implement a proposal which would preclude ratepayers from receiving the benefits of storage and hedging.

The Company's proposal would also alter customers' rights to receive the benefits of margins from non-BGSS sales. The fixed Non-Gulf Coast Cost rate, which is to be in effect through December 31, 2003, would reflect the I&C customers' current share of margin revenues. However, these customers will not receive the benefit of any increased margin revenues that may result from the Affiliate's control of the transferred contracts, nor would they benefit from any Board decision to change the Company's former 85%/15% sharing formula for capacity releases and off-system sales, which is currently being litigated in Docket

No. GR00070491. Further, the Affiliate could partially or completely offset the margins embedded in the Non-Gulf Coast Cost rate by selecting a Gulf Coast Cost rate above the floor level.

It is also unclear whether ratepayers will receive proper compensation for the costs of the Company's LNG and LPG facilities. These peaking facilities are used to supply the last increment of usage on the coldest days. The costs of the Public Service's peaking facilities are included in the Company's balancing charges. All revenues collected by the Company for balancing services are to be paid to the Affiliate under the Requirements Contract, while Public Service continues to own the facilities, carry the inventories, and incur the related operation and maintenance costs. The current version of the Requirements Contract states that the Affiliate will pay amounts "billed by [Public Service]" for actual operation and maintenance costs plus the "return of and return on" the Company's investment in the peak shaving facilities. However, it remains unclear how costs will be allocated to the facilities, whether depreciation is a chargeable cost, and on what basis existing inventories will be purchased and used by the Affiliate.

In addition to these lost benefits, residential customers, at the time of their proposed transition to MPGS pricing on April 1, 2004, would also lose the rate stability provided by their current levelized annual pricing mechanism. Schedule 3 illustrates the loss of price stability that would be experienced by residential customers. From a $5.77 per dekatherm level in August 2000, the Company's MPGS-GS rate increased to $12.79 per dekatherm by January 2001, an increase of 122%. The monthly price variation over the past 10 months has ranged from a 30% decrease to a 46% increase.

Q. WOULD YOU PLEASE COMMENT ON THE PROPOSED PRICING OF BGSS AFTER DECEMBER 31, 2003?

A. Beginning in 2004, the proposed pricing mechanism becomes even more problematic. Paragraph 7 of the Joint Position and some of the Company's responses to discovery state that the Non-Gulf Coast Cost component of MPGS rates is to be "market priced" after December 31, 2003. It is not entirely clear how this change will be implemented. If interstate pipeline capacity is to be truly market priced, this rate component could be priced at very high rates during periods when pipeline capacity is constrained. As an example, during the 2000-2001 winter season, spot prices for natural gas delivered to New Jersey reached $25 per dekatherm and higher, reflecting a very substantial premium over the tariffed rates charged by the interstate pipelines.

At the May 22, 2001 hearing, Company witness David Wohlfarth testified that the Company's intent was to continue cost-based pricing for Non-Gulf Coast Costs. According to Mr. Wohlfarth, the $1.26 per dekatherm rate proposed to be in effect through December 31, 2003 would be "unfrozen" and adjusted annually to reflect actual costs. However, the Joint Position has not been amended to permit cost-based pricing for the Non-Gulf Coast Cost component. Further, even under the approach described by Mr. Wohlfarth, the Non-Gulf Coast Cost component would be based on a portfolio structured completely at the discretion of the unregulated Affiliate, thus limiting the Board's practical ability to review the underlying costs. In either event, the limited price protection provided by the ceiling rates would, in all likelihood, become even further attenuated after December 31, 2003.

Q. WOULD YOU PLEASE COMMENT ON THE COMPANY'S ARGUMENTS THAT THE AVAILABILITY OF COMPETITIVE ALTERNATIVES WILL PROVIDE SUFFICIENT PRICE PROTECTION FOR CONSUMERS?

A. I note first that, based on my understanding of EDECA, the Legislature has determined that consumers should have a regulated rate as a backstop to prices determined in the competitive market. A market-based rate does not meet this objective.

I also disagree with the Company's assertion that the competitive market will assure reasonable prices for consumers. No one can truthfully assert that adequate competitive alternatives are available for Public Service's residential and small commercial customers today. As I discuss in more detail below, the Joint Position includes a number of measures intended to promote competition in Public Service's territory, but there are no guarantees. To date, Public Service's customer choice programs have not resulted in any significant competition for smaller customers. During Public Service's initial pilot residential choice program and during the period when it had an expanded pilot, the Company failed to attract any TPSs into its market. Even with the economic incentives after the Board's natural gas unbundling order, no major migration to transportation was experienced. As shown on Schedule 4, by September 2000 Public Service only had 5% of its General Service and 0.1% of its residential customers using TPS gas supplies. It is unclear whether the current proposal will have a higher level of success in establishing and maintaining a competitive market, especially as the proposed capacity release programs, economic incentives, and BGSS pilot program expire over the next few years. Further, if the proposed transfer is allowed, the Board's ability to implement further measures to encourage competition will be very limited.

Q. IS THE COMPANY PROPOSING ANY RESTRICTIONS ON CUSTOMERS' ABILITY TO CHOOSE A COMPETITIVE ALTERNATIVE SUPPLIER IN RESPONSE TO UNREASONABLE MPGS PRICES?

A. Yes. The Company's proposed tariffs for MPGS service would require customers to take service under an initial term of one year, subject to automatic renewals for successive one-year terms. With MPGS customers committed to such one-year service terms, a situation is created where pricing abuse is possible, and where customers remain without free market choice.

Q. WHAT RECOURSE WOULD THE BOARD HAVE IF MPGS WERE TO BE IMPLEMENTED, AND THEN IT WAS DETERMINED THAT MPGS RATES WERE UNREASONABLE?

A. Under the Company's proposal, very little. The Public Service proposal would severely restrict the Board's ability to make changes in MPGS pricing. Under the Requirements Contract, the Affiliate would be entitled to compensation including all amounts billed by the Company under its MPGS tariffs. The Board could change the Company's tariffs, but this would trigger the Regulatory Risk provisions in section 11.2 of the Requirements Contract. The Affiliate would then have the right to enter into a renegotiation of the terms of the contract with the objective of "preserv[ing] the economic value of the Contract to each Party . . ." In the event this effort were to fail, the parties would then proceed to arbitration, in a proceeding in which the arbitrators would be obligated to:

> endeavor to identify solutions that compensate [the Affiliate] for the services it provides under the Contract consistent with the market value of the service and which enables [Public Service] to provide BGSS service to its customers in a manner and at a price comparable to the manner of service and price for service that third-party gas suppliers operating in New Jersey would provide to similarly situated customers; ....

In other words, the arbitrators would be explicitly prohibited from considering the EDECA requirement that BGSS provide a regulated backstop against market power.

According to the Company proposal, the arbitrator's decision would be binding on the Board (Tr. 449-450). The Board, having approved the Requirements Contract, could find its authority to deny pass-through recovery of the amounts found by the arbitrator to be payable to the Affiliate subject to challenge. At the very least, the Company's proposal raises serious questions about the Board's ability to exercise its ratemaking authority if it were to approve the Requirements Contract as proposed by the Company.

Q. WOULD THE COMPANY'S PROPOSAL HAVE ANY IMPACT ON THE RATES CHARGED TO RESIDENTIAL CUSTOMERS DURING THE PERIOD WHEN THEY REMAIN SUBJECT TO LEVELIZED ANNUAL PRICING?

A. This is not entirely clear. The Joint Position states that residential customers will retain their current cost-based rates through March 31, 2001. However, with procurement and system management in the hands of an unregulated entity, it is unclear how the Board will continue to exercise its current oversight of gas procurement and gas costs for residential customers. To give just one example, the Requirements Contract does not require the Affiliate to use its storage capacity to benefit residential customers, nor is there any provision that would prevent the Affiliate from using low-cost stored gas for off-system sales and replacing it with high cost gas to be ultimately charged to residential customers.

Further the current version of the Requirements Contract includes a provision apparently intended to limit the Board's ability to review the prudency of the Affiliate's procurement and gas supply management activities on behalf of residential customers. The May 30, 2001 draft of the Requirements Contract includes a new section 2.2, which provides, in part, as follows:

> [Public Service] agrees to pay [Affiliate] the actual Gulf Coast Cost of Gas and Non Gulf Coast Cost of Gas ... incurred by [Affiliate] to supply the gas required by [Public Service] to serve [Public Service's] customers under Rate Schedule CS-RSG.

This provision would appear to require Public Service to pay the Affiliate the <u>actual</u> gas costs incurred by the Affiliate to supply the Company's residential customers, rather than <u>prudently incurred</u> costs as determined by the Board.

It is also unclear how other benefits currently received by residential customers will be preserved. There is no provision in the current version of the Joint Position to preserve these customers' rights to margin revenues. The proposed new Addendum to Paragraph 12 of the Joint Position may also affect the residential customers' margin revenues. The Addendum, which was apparently negotiated to induce large cogenerators to sign the Joint Position, provides these customers with access to interstate transportation and storage resources which the Affiliate determines are not needed to meet its obligations under the Requirements Contract. By providing gas cogenerators such preferential access to "surplus" capacity, there would be a diversion of potential margins from residential sales customers who would otherwise be credited for the margins through the LGAC. The Company also states that the Affiliate would bear all of the risks of failure to recover the fixed portions of its Non-Gulf Coast Costs in the event I&C customers were to migrate to TPSs during the period when the Non-Gulf Coast Cost component of its MPGS rates remained frozen. However, the Company has not yet determined how these costs will be allocated between residential and non-residential customers, so as to avoid including these amounts in the rates charged to residential customers.

C. THE COMPANY'S PROPOSAL UNREASONABLY DISCRIMINATES AGAINST MARKET PARTICIPANTS OTHER THAN PSEG AFFILIATES, IN VIOLATION OF THE BOARD'S INTERIM AFFILIATE RELATIONS STANDARDS.

Q. WHAT IS YOUR UNDERSTANDING OF THE BOARD'S INTERIM AFFILIATE RELATIONS STANDARDS, AS THEY RELATE TO THE PROPOSED TRANSACTIONS?

A. Section 3 of the Affiliate Standards includes rules governing a gas public utility's conduct. Part 1 of Section 3 states:

> An electric and/or gas public utility shall not unreasonably discriminate against any competitor in favor of its affiliate(s) or related competitive business segment ....

Part 3 of Section 3 states,

> An electric and/or gas public utility shall provide access to utility information, services, and unused capacity or supply on a non-discriminatory basis to all market participants, including affiliated and non-affiliated companies . . .

It is my understanding that these provisions prohibit utilities from unreasonably discriminating in favor of an affiliate and against other participants in the State's energy markets with regard to utility information, service, and capacity or supply.

Q. BASED ON YOUR UNDERSTANDING OF THE AFFILIATE STANDARDS, HOW WOULD THEY APPLY TO THE PROPOSED TRANSACTIONS?

A. The Company's proposal to provide both the contract transfer and the Requirements Contract to an affiliate on a sole source basis appears to violate the above provisions. There are other TPSs that could have, and I believe would have, bid on these transactions. While any transfer of capacity contracts would have to be made at prevailing FERC rates, the terms and conditions of the Requirements Contract could have been bid more favorably by the TPSs. For a major gas supplier, the acquisition of about 1.6 million customers along with the transportation and storage capacity to serve their demand would represent a substantial sales and profit opportunity.

In response to a discovery request (RAR-T-16) requesting an explanation why these transactions were not offered to non-affiliated entities, the Company's response was that,

> . . . no third party supplier, has sought out a release of capacity for one year, let alone for the term of any portion of the contract portfolio. This confirms the Company's belief . . . That the Company has largely unique opportunities to extract value from the contracts. In these circumstances, the Company does not believe that it is likely that the entities would take on a transfer on comparable terms and, at the same time, offer a more advantageous requirements contract.

To put this statement into context, several facts should be noted. The fact that no TPS historically sought out capacity, even for a single year, is not particularly relevant or indicative of whether or not a TPS would have bid on the capacity rights or the Requirements Contract. The Company's past capacity assignments did not include storage, nor did they provide aggregated customer demand or the other benefits that Public Service is proposing to transfer to its Affiliate.

It is also instructive to note that the Company has stated in its response to discovery request RAR-T-15 that its Affiliate:

> . . . is willing to assume the risk of recovering the costs related to these above-market contracts as set forth in the Petition, because it believes, in a deregulated environment, that its trading capabilities and knowledge of Northeastern markets, its extensive experience in coordinating the use of the portfolio of transportation and storage entitlements will provide opportunities, though not without risk, to offset the burden of contract costs that exceed market value.

In response to another discovery request (RAR-T-13) the Company stated that it would transfer to the Affiliate "those groups responsible for gas supply, planning procurement and trading." Thus, the Company seems to be stating that the Affiliate would obtain trained staff, whose salaries are being recovered in base rates, who could manage the Company's gas supply portfolio so as to make its on-going value higher than its cost. If the Company's employees do in fact possess "unique" experience and skills, this provides the Affiliate with an unreasonable preference and provides windfall gains to its shareholders.

Q. WOULD THE PROPOSED TRANSACTIONS RESULT IN ANY OTHER UNREASONABLE PREFERENCES?

A. The transactions could create an unreasonable preference in favor of the Company's electric generation affiliate, to the detriment of other participants in the State's electric markets. According to Mr. Wohlfarth, the electric generation affiliate receives balancing service, which involves the use of the Company's peaking facilities as well as its interstate transportation and storage resources. The Board's decision to allow these resources to continue to be dedicated to the electric generation affiliate appears reasonable at the present time, while the electric generation affiliate remains obligated to supply all of the Company's basic generation service customers and is compensated based on regulated rates. However, this preference may not be reasonable in the future, as the generation affiliate becomes free to use these resources to participate in the State's electricity markets. As proposed by the Company, the Affiliate, apparently would be under no obligation to give other electric generators non-discriminatory access to these resources. In my opinion, this creates an unreasonable preference in favor of the electric generation affiliate.

Q. DOES THE COMPANY'S PROPOSED ADDENDUM TO PARAGRAPH 12 OF THE JOINT POSITION REMEDY THIS PROBLEM?

A. No, it does not. As noted above, the Addendum provides the Company's cogeneration customers with preferential access to capacity which could otherwise be used to benefit BGSS customers. It would not apply to the capacity currently dedicated to the Company's electric generation affiliate (Tr. 541-542).

D. THE COMPANY'S PROPOSAL DOES NOT PROVIDE AN APPROPRIATE FRAMEWORK FOR FOSTERING COMPETITION IN NEW JERSEY'S RETAIL NATURAL GAS MARKETPLACE.

Q. MR. WOHLFARTH'S TESTIMONY IN SUPPORT OF THE JOINT POSITION STATES THAT IT WOULD PROVIDE A COMPREHENSIVE PROGRAM TO FOSTER COMPETITION FOR NATURAL GAS SERVICES IN PUBLIC SERVICE'S TERRITORY. DO YOU AGREE?

A. No, I do not. In the current proposed program there are three basic components which would facilitate the entry of competitive suppliers: voluntary assignment of transportation and storage capacity; economic incentives for participation; and the establishment of a bidding framework for suppliers to acquire aggregated customers in relatively large numbers without excessive selling and administrative costs. The Company has not identified any reason why all of these components could not be offered by the Company without the need for a contract transfer and Requirements Contract. This approach is preferable for the Company's BGSS customers, who would retain protections contemplated by EDECA until robust competition had been established. Further, the proposed measures included in the Joint Position all would expire over the next few years. The Board would have a much greater ability to implement additional measures to encourage competition if the Company were to retain its gas capacity and supply resources.

Q. THE COMPANY HAS STATED THAT THE JOINT POSITION REPRESENTS A "BALANCE OF INTERESTS" THAT SHOULD BE IMPLEMENTED AS A PACKAGE. DO YOU AGREE?

A. I strongly disagree. The Joint Position represents the interests of Public Service, its Affiliate, a few potential TPSs, and a very limited group of large volume customers who would effectively be exempt from the provisions which will adversely affect BGSS customers. The proposed Addendum to Paragraph 12 of the Joint Position is a good example of the Company's effort to find support for its proposal by providing preferential concessions to select parties. As noted above, the Addendum would provide cogenerators with preferential access to transportation and storage capacity, to the detriment of the Company's BGSS customers.

Q. WOULD THE JOINT POSITION PROVIDE ANY TANGIBLE RATEPAYER BENEFITS?

A. It would not. The Company has stated that the proposed transactions will insulate ratepayers from stranded costs, but this is questionable. As explained above and in Mr. Chernick's testimony, the Company's proposal is more likely to insulate ratepayers from stranded benefits, which would be appropriated by the Affiliate without compensation to ratepayers. In the unlikely event stranded costs were to occur, the Affiliate would retain an option to return up to 50 percent of the transferred contracts back to Public Service if the Requirements Contract were not renewed.

It is also questionable whether the Joint Position would succeed in creating robust competition in the State's natural gas marketplace. The Joint Position has inherent limitations which could actually defeat the Board's ability to assure that a robust competitive market would be created and maintained over the long term. Most important, the transactions would limit the Board's ability to make the transferred contracts accessible to potential competitive suppliers. The Affiliate would offer capacity and storage releases, but subject to a number of limitations, including the following:

- There would be a three-year "window" in which TPSs could obtain temporary and/or permanent access to transportation and storage capacity, in amounts corresponding to the number of the Company's previous sales customers they serve.
- Permanent releases of transportation and storage capacity would be subject to "turnback" rights at the time the underlying contracts were subject to renewal. At that time, any capacity in excess of that necessary to serve the TPS' then existing migration customer base would be returned to the Affiliate.
- At the conclusion of these programs, the capacity would be in the hands of the Affiliate and/or TPSs, and they would be under no obligation to make capacity available to additional market entrants.

The economic incentives would be similarly limited. At the outset, it is important to note that economic incentives may not always be effective. Incentives have been developed as part of the unbundling process for the New Jersey gas utilities, but unfortunately such incentives have been negated as a result of recent high price volatility in the wholesale gas market. Further, the economic incentives in the Joint Position would all expire in 2004. This raises the prospect that TPSs might exit the market when the incentives expired. The Joint Position's commitment of ratemaking discretion to the Affiliate would limit the Board's ability to implement further incentives after 2004.

The BGSS pilot program is also limited. The Joint Position does not include a commitment to implement this program, only an agreement to participate in a collaborative. Further, this program would be subject to a number of limitations, including the following:

- The program would be limited to 30 percent of the Company's BGSS customers, with no guarantees that this target would be reached.
- Participation would be limited to a maximum of three TPSs, each of which would serve an equal number of the participating customers.
- As discussed in more detail below, BGSS customer representatives, as well as potential suppliers not signing the Joint Position, would be excluded from the collaborative which would define important parameters of the program.
- The program is limited to a two-year term, from April 1, 2003 through March 31, 2005.

This program would allow a limited number of large suppliers to gain a share of the Company's interstate transportation and storage resources under the proposed capacity release programs. In return for this benefit, the winning bidders would be obligated to provide service for two years, with no obligation to remain in the market for either BGSS or competitive service.

Overall, these programs appear to have been designed to reflect the interests of the Company and the few large suppliers that have signed the Joint Position. The economic incentives and BGSS pilot would remain in effect long enough for a few major suppliers to obtain access to a share of the Company's interstate pipeline and capacity contracts. Thereafter, the transferred contracts would remain within the control of the Affiliate and TPSs and beyond the reach of the Board, thus limiting the Board's ability to expand the availability of competitive alternatives for consumers.

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S POSITION THAT IT AND ITS AFFILIATE ARE ENTITLED TO THE CONTRACT TRANSFER AND REQUIREMENTS CONTRACT AS A BALANCE TO THE RISKS INHERENT IN OTHER ASPECTS OF THE JOINT POSITION?

A. The risks are greatly overstated. The principal risk identified by the Company is the risk of stranded costs arising from the transferred contracts in the event the Company loses customers as a result of the programs (Tr. 527-528). In the current constrained market for capacity I believe it unlikely that any capacity not released to TPSs would become "stranded." Even if stranded costs should occur, the risk of non-recovery is small if the Company maintains the cost-based BGSS service contemplated by EDECA. In any event, if stranded costs are believed to be a material liability by the Company, it could, as part of a capacity assignment or BGSS pilot program, require TPSs to take some minimum portion of the contracts associated with the customers who migrate to them.

Q. WOULD YOU PLEASE EXPLAIN AND DISCUSS THE FUNDING MECHANISMS FOR THE PROPOSED INCENTIVES?

A. The first incentive is based on the Stipulation in the Company's gas unbundling proceeding, which provided for an incentive of $0.14 per dekatherm, with an additional $0.08 to be considered in a second phase. The Joint Position would implement the additional $0.08 incentive. This incentive would be funded from prior overcollections which were segregated in a special incentive fund which was created in the unbundling Stipulation. The overcollection otherwise would have been credited to sales customers.

The second incentive is associated with the Company's Gas Cost Underrecovery Adjustment ("GCUA"), which the Board has authorized to recover gas cost undercollections beginning on December 1, 2001. The amortization of the GCUA would be collected from sales customers, but customers switching to TPSs would receive a $0.35 per dekatherm credit. This credit also would be paid by sales customers, who would be responsible for the GCUA amortization not paid by customers migrating to TPSs.

The third incentive is an additional credit of $0.18 per dekatherm, which would become effective for customer classes not attaining at least a 20 percent migration rate within one year after a Board Order approving the Joint Position. This last incentive would be funded with $21.4 million from the special incentive fund established in the unbundling proceeding and with up to $15.0 million from interruptible credits which otherwise would be credited to sales customers.

Q. BASED ON THE FUNDING FOR THE ECONOMIC INCENTIVES, ARE THEY RELEVANT TO THE CONTRACT TRANSFER OR THE REQUIREMENTS CONTRACT?

A. They are not. They are beneficial to help stimulate the entry of TPSs and thereby facilitate the development of a competitive market, but they neither enhance nor do they emanate from the proposed transactions. Therefore, it should be understood that the incentives are not some form of *quid pro quo* for the contract transfer.

Q. HOW SHOULD THE BOARD PROCEED TO DEVELOP A COMPETITIVE NATURAL GAS MARKETPLACE?

A. The Board should direct the Company to implement programs such as those in the Joint Position without the contract transfer and Requirements Contract. The Board should, however, make some modifications to the programs as proposed.

Q. HOW WOULD YOU PROPOSE TO MODIFY THE CAPACITY RELEASE PROGRAMS?

A. These are some positive programs, which could be implemented. However, as discussed in detail in Mr. Chernick's testimony, it is important for the Board to retain its ability to control 7the limited interstate transportation and storage resources serving New Jersey, until there is assurance that robust competition has been established. The programs included in the Joint

Position do not have adequate provision to ensure that the benefits of the Company's interstate transportation and storage resources will be received by consumers. For example, the Initial FT Capacity Release Program and the Citygate Storage and Redelivery Program would have one-year terms, but it is not clear that a TPS would have an obligation to remain in the market for that period, or to return capacity if it were to leave the market. Similarly, the Permanent Capacity Release/Assignment Program provides for a "turnback" of the capacity at the time the underlying contract is subject to renewal, but it is unclear whether the TPSs would be under an obligation to remain in the market or return capacity if it were to exit the market before this time, or after the renewal.

Q. WHAT ARE YOUR RECOMMENDED MODIFICATIONS TO THE PROPOSED ECONOMIC INCENTIVES?

A. Since the incentives would be funded by ratepayers, it is important to assure that the amounts are no higher than needed to encourage competitive offers to consumers. The proposed incentives, including the $0.14 per dekatherm already in effect as a result of the unbundling Stipulation, total $0.57 per dekatherm or $0.75 if the additional incentive is implemented for customer classes that do not reach the 20 percent migration target. These amounts were established as a result of negotiation between the Company and the TPSs signing the Joint Position. They may be somewhat higher than necessary. In earlier unbundling proceedings TPSs have indicated that incentives should be set at around 10 percent of the cost of gas. Based on this benchmark, the proposed incentives may be somewhat high, especially if the $0.18 per dekatherm additional incentive is included.

Q. WHAT CHANGES DO YOU PROPOSE FOR THE BGSS PILOT PROGRAM?

A. Fundamentally, the proposed program facilitates customer aggregation, an activity which has been consistently supported by the Ratepayer Advocate. By developing a customer pool, the program will enable TPSs to serve a large number of customers without high marketing and administrative expenses. As a concept, the program is very positive, but a large number of program details need to be worked out before any benefits will be realized.

Q. BASED ON YOUR REVIEW, WHICH PROGRAM DETAILS NEED TO BE SPECIFIED AND WHICH MAY NEED MODIFICATION?

A. The Company first needs to determine how its proposed collaborative is going to operate. At present, both the Board Staff and the Ratepayer Advocate are not specifically mentioned in the Joint Position as participants in the planned collaborative, though Company witness David Wohlfarth has expressed a willingness to include both. Assuming that both the Staff and the Ratepayer Advocate will be part of the collaborative, the following need to be specified:

A. TPS Obligations: Is it the intent to have TPSs assume only supply obligations, or is it intended that the proposed program will actually transfer BGSS responsibilities from the Company?

B. Non-Discriminatory Access: Will the program include all customers regardless of their credit or income status, or will there be potential screening for program eligibility?

C. Enrollment Procedures: How will customers be chosen as potential participants in the pool? Will the pool be open to all customers, or will some form of lottery or sample be utilized?

D. Program Limitations: The program is limited to a maximum of 30 percent of BGSS customers and a two year duration. Could such program parameters be modified under the Company's proposal?

E. Program Commitment: Based on the Stipulation, is there a commitment by the Company and the other parties to guarantee the implementation of a comparable program, or is the Stipulation merely an expression of intent?

Q. TURNING TO POSSIBLE PROGRAM MODIFICATIONS, WHAT ASPECTS OF THE PROGRAM DO YOU RECOMMEND BE ALTERED?

A. Based on the language of the Joint Position, there are four parameters of the Program which should be changed. First, the bidding process should not limit the number of TPSs that can participate in the program. There appears to be no logical reason why more than three TPSs could not have their bids accepted, other than to limit participation to large suppliers such as those participating in the Joint Position. In order to encourage TPSs to actively market in the service territory, it would be beneficial if a larger number of them could gain an initial, or more material, presence in the market through the program. The more TPSs that are involved, the more likely that the Program will help develop a viable competitive market.

Second, it appears that the selection process is to be controlled and administered by the TPSs and MAPSA. The TPSs' interests in the selection process are not necessarily compatible with customer interests. Accordingly, the Joint Position should specify broader participation in the selection process, including the Company, Board Staff, the Ratepayer Advocate, as well as other potential suppliers as acknowledged by Mr. Wohlfarth during cross (Tr. 533).

Third, the Company appears to make provision for an opt-in enrollment procedure, but only if there is a determination that this is needed. If the selection process is controlled by the TPSs, it is not clear that such an opt-in provision will be determined to be needed. If the program is to be implemented, it should provide for enrollment based on an affirmative opt-in type of notification. The Board's concern about customer slamming is well placed, and this program should be designed to lessen any mechanisms which might create or appear to create tacit approval of automatic enrollment without direct customer authorization.

Fourth, page 15 of the Joint Position states that the collaborative "shall address the bidding process, parameters for deciding the qualifications of bidders, pricing, regulatory requirements and other relevant matters." The Company's Response to RAR-T-106 states that pricing options will be limited so that "the bids can be intelligently evaluated." There seems to be no rationale for having the bidding process restrict how a TPS can price its bid. The fundamental benefit of alternative suppliers is that they can offer innovative service and pricing options to customers. If the program is going to limit the pricing parameters of the bids, then a major component of customer choice is going to be lost.

VI. SUMMARY OF POLICY ISSUES

Q. WOULD YOU PLEASE SUMMARIZE WHY YOU DO NOT BELIEVE THAT THE CONTRACT TRANSFER AND THE REQUIREMENTS CONTRACT ARE IN THE PUBLIC INTEREST?

A. The first, and perhaps most pertinent, reason is that it is fundamentally inconsistent with the Legislature's intent to provide consumers with the inherent protections of affordable BGSS service. Consumers are entitled to receive regulated, cost-based service provided by a regulated utility, until the Board determines this is no longer in the public interest. Thereafter, customers remain entitled to regulated BGSS, though it may be provided by non-utility suppliers and based either on costs or competitive bidding. The Public Service proposal would subvert EDECA's intent. Subject only to a short delay for residential customers, BGSS customers would be subject to prices set at the discretion of an unregulated entity, whose procurement practices and pricing would be essentially beyond the Board's regulatory oversight, thus creating the opportunity for control by an unregulated monopoly.

The Public Service proposal would also preempt the Board's ability to structure BGSS service as part of its generic proceeding to consider whether non-utility suppliers should be permitted to bid for BGSS service. A proposal to transfer contracts should be considered only after the Board has determined how BGSS should be provided and the need for continuing access to the Company's interstate transportation and storage resources to ensure a reliable, reasonably priced BGSS supply. As explained in Mr. Chernick's testimony, an irrevocable transfer should be considered only after robust competition has been firmly established, after appropriate market studies and competitive bidding.

Q. IN YOUR OPINION, AT WHAT POINT WILL THE NATURAL GAS MARKET BE SUFFICIENTLY COMPETITIVE TO WARRANT CONSIDERATION OF A CONTRACT TRANSFER?

A. I have not developed any analysis that would define a standard for determining when such competition exists. The Georgia legislature required at least five non-affiliated suppliers to be active in the market, and serving at least one-third of the peak day requirements of firm distribution customers (Ga. Stat. Ann. 46-4-154). However, a benchmark based solely on the level of customer migration may not be sufficient. As demonstrated in recent months, such market shares can erode, and suppliers can quickly exit the market, in response to high and/or volatile gas prices.

Q. MR. LELASH, A NUMBER OF TPSs HAVE SIGNED THE PROPOSED STIPULATION. SHOULD THEIR ACCEPTANCE OF ITS TERMS AND CONDITIONS BE SEEN BY THE BOARD AS AN INDICATION THAT THE CONTRACT TRANSFER AND THE REQUIREMENTS CONTRACT ARE REASONABLE?

A. No, it should not. The interest of the Company, its Affiliate, the TPSs, and the Company's large cogeneration customers is to achieve profits, it is not necessarily to develop a competitive market. In drafting the Joint Position, the signing parties negotiated mutually acceptable terms and conditions. Unfortunately, the residential ratepayers were not represented in those negotiations, and their interests were not incorporated into the Joint Position. The signatories to the Joint Position have no right to bargain away BGSS customers' rights to receive fully regulated BGSS and to receive cost-based service from the utility until the Board determines otherwise. Issues concerning ratepayer protections, supply reliability, and whether or not the market offers reasonable competitive choices should not be decided solely by special interest groups.

Q. DOES THE STIPULATION OF SETTLEMENT CLEARLY DEFINE WHAT RATEPAYER BENEFITS WILL BE DERIVED FROM ITS TERMS AND CONDITIONS?

A. It does not. The Joint Position does not ensure that a competitive market for gas supply will be created, nor does it address what happens if competition becomes unworkable in the future. In effect, the Joint Position does not have any meaningful exit strategy, nor does it provide for Board intervention if the prices for gas service cease to be just and reasonable. In my opinion, the Joint Position offers no tangible benefit to ratepayers, but rather increases price and supply uncertainty and diminishes existing consumer protection.

In the transition to a competitive market, there is the real potential for ratepayer harm as has been evidenced by the California deregulation initiative. The California experience provides clear evidence of the need during such a transition for the regulatory agency to delineate the interests of supplier and special interest stockholders from those of the basic utility consumers. In the end analysis, since the objective of deregulation is to provide lower costs to the consumers, the protection of their interests must be given priority.

Q. MR. LELASH, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS MATTER?

A. Yes, it does.

VI. SUPPORTING SCHEDULES

Schedule 1

Public Service Electric & Gas Company
Comparative GS Tariff Rates
(Rates per dekatherm with SUT)

	CS-GS	MPGS	Ceiling	ª MPGS	ª Ceiling
June, 2000	$ 5.46	$ 5.72	$ 8.19	$0.26	$2.73
July	5.80	6.06	8.36	0.26	2.56
August	5.50	5.77	7.55	0.27	2.05
September	6.13	6.40	8.56	0.27	2.43
October	6.85	7.12	9.42	0.27	2.57
November	6.79	7.06	8.43	0.27	1.64
December	8.49	8.75	10.45	0.26	1.96
January, 2001	12.53	12.79	15.49	0.26	2.96
February	10.53	10.79	10.84	0.26	0.31
March	6.83	7.53	9.13	0.70	2.30
April	6.83	7.24	9.48	0.41	2.65
May	6.09	6.71	8.78	0.62	2.69
Averages	$ 7.32	$ 7.66	$ 9.56	$0.34	$2.24

SOURCES: Public Service’s Commodity Charge Summary and MPGS monthly tariffs.

Public Service Electric & Gas Company
MPGS Monthly GS Commodity Price
(Rates per dth)

	Floor Price	Ceiling Price	MPGS Rate	MPGS Rate Minus Floor
June 2000	$ 5.46	$ 8.19	$ 5.72	$0.26
July	5.80	8.36	6.06	0.26
August	5.16	7.55	5.77	0.61
September	6.13	8.56	6.40	0.27
October	6.85	9.42	7.12	0.27
November	6.79	8.43	7.06	0.27
December	8.49	10.45	8.75	0.26
January 2001	12.53	15.49	12.79	0.26
February	8.95	10.84	10.79	1.84
March	7.26	9.13	7.53	0.27
April	6.97	9.48	7.24	0.27
May	6.45	8.78	6.71	0.26
Averages	$ 7.24	$ 9.56	$ 7.66	$0.43

SOURCES: Company responses to RAR-T-20 Revised and RAR-T-151.

Public Service Electric & Gas Company
MPGS-GS Monthly Pricing
(Rates per dth)

	MPGS-GS	Percentage Change	Cumulative Change
August 2000	$5.77	- %	- %
September	6.40	10.9	10.9
October	7.12	11.3	23.4
November	7.06	(0.8)	22.4
December	8.75	23.9	51.6
January 2001	12.79	46.2	121.7
February	10.79	(15.6)	87.0
March	7.53	(30.2)	30.5
April	7.24	(3.9)	25.5
May	6.71	(7.3)	16.3

SOURCES: Company Responses to RAR-T-20 Revised and RAR-T-151.

Public Service Electric & Gas Company
Sales and Transportation Customers & Usage

Classes of Service	Customers		Dth Usage	
	12/31/99	9/1/00	12/31/99	9/1/00
Large Volume				
CSLV	8,500	8,700	28,553	29,225
FTLV	6,900	6,700	42,930	41,685
Total	15,400	15,400	71,483	70,910
FT %	44.8%	43.5%	60.1%	58.8%
General Service				
CSGS	156,000	156,500	31,684	31,785
FTGS	9,000	8,500	4,460	4,212
Total	165,000	165,000	36,144	35,997
FT %	5.5%	5.2%	12.3%	11.7%
Residential				
CSRSG	1,428,000	1,426,600	179,071	178,896
FTRSG	1,400	4,300	176	539
Total	1,429,400	1,430,900	179,247	179,435
FT %	0.1%	0.3%	0.1%	0.3%

SOURCE: Company Response to RAR-T-7, page 2.

VII. APPENDIX: PRIOR R.W. LELASH TESTIMONIES

R. W. LELASH'S REGULATORY TESTIMONIES
(1996 to Present)

194. Vermont, Green Mountain Power Corporation (Docket No. 5857) Rate of Return and Gas Remediation Recovery Testimony for the Vermont Department of Public Services (January, 1996).

195. Rhode Island, Providence Gas Company, (Docket No. 2374) Gas Tariff Restructuring Testimony for the Rhode Island Division of Public Utilities (February, 1996).

196. Rhode Island, Providence Gas Company (Docket No. 1673) Gas Price Hedging Testimony for the Rhode Island Division of Public Utilities (August, 1996).

197. Philadelphia Gas Commission, Philadelphia Gas Works (1997 Gas Cost Rate Filing) Gas Procurement and Policy Testimony for the Public Advocate (September, 1996).

198. Georgia, Atlanta Gas Light (Docket No. 6717-U) Gas Service Unbundling Testimony for the Georgia Public Service Commission (January, 1997).

199. FERC, Cleveland Electric and Toledo Edison (Docket No. ER97-529-000, Consolidated) Rate of Return Rebuttal Testimony for Centerior Energy (April, 1997).

200. Rhode Island, Providence Gas Company (Docket No. 2581) Price Stabilization Plan Testimony for the Rhode Island Division of Public Utilities (August, 1997).

201. New Jersey, New Jersey Natural Gas Company (Docket No. GT96070524) Gas Policy Testimony for the New Jersey Division of the Ratepayer Advocate (August, 1997).

202. Vermont, Green Mountain Power Corporation (Docket No. 5983) Gas Remediation Recovery Testimony for the Vermont Department of Public Service (October, 1997).

203. Philadelphia Gas Commission, Philadelphia Gas Works (1998 GCR Proceeding) Gas Procurement and Policy Testimony for the Public Advocate (December, 1997).

204. Vermont, Green Mountain Power Corporation (Docket No. 5983) Gas Remediation Surrebuttal Testimony for the Vermont Department of Public Service (December, 1997).

205. Delaware, Delmarva Power & Light Company (Docket No. 97-293F) Gas Price Hedging Testimony for the Delaware Public Service Commission (January, 1998).

206. Delaware, Artesian Water Company (Docket No. 97-340) Rate of Return Testimony for the Delaware Public Service Commission (February, 1998).

207. Georgia, Atlanta Gas Light Company (Docket No. 8390-U) Regulatory Policy Testimony for the Energy Service Providers Association (March, 1998).

208. New Jersey, Public Service Electric & Gas Company (Docket No. GR97110839) Gas Procurement and Policy Direct Testimony for the New Jersey Division of the Ratepayer Advocate (April, 1998).

209. New Jersey, Public Service Electric & Gas Company (Docket No. GR97110839) Gas Procurement and Policy Surrebuttal Testimony for the New Jersey Division of the Ratepayer Advocate (April, 1998).

210. Philadelphia Gas Commission, Philadelphia Gas Works (1998 GCR Proceeding) Gas Price Hedging Position Statement for the Public Advocate (May, 1998).

211. Philadelphia Gas Commission, Philadelphia Gas Works (1999 GCR Proceeding) Gas Procurement and Policy Testimony for the Public Advocate (October, 1998).

212. Georgia, Cumberland Pipeline Investigation (Docket No. 10064-U) Regulatory Policy Testimony for East Tennessee Natural Gas Company (March, 1999).

213. New Jersey, Generic Unbundling Proceeding (Docket No. GX99030121) Gas Policy Testimony for the New Jersey Division of the Ratepayer Advocate (July, 1999).

214. New Jersey, Public Service Electric & Gas Company (Docket No. GO99030124) Gas Unbundling Testimony for the New Jersey Division of the Ratepayer Advocate (July, 1999).

215. Philadelphia Gas Commission, Philadelphia Gas Works (2000 GCR Proceeding) Gas Procurement and Policy Testimony for the Public Advocate (September, 1999).

216. New Jersey, Generic Unbundling Proceeding (Docket No. GX99030121) Gas Policy Surrebuttal Testimony for the New Jersey Division of the Ratepayer Advocate (September, 1999).

217. New Jersey, Public Service Electric & Gas Company (Docket No. GO99030124) Gas Unbundling Surrebuttal Testimony for the New Jersey Division of the Ratepayer Advocate (September, 1999).

218. Pennsylvania, Columbia Gas of Pennsylvania, Inc. (Docket No. R-00994781) Restructuring Testimony for the Pennsylvania Office of Consumer Advocate (October, 1999).

219. Pennsylvania, Columbia Gas of Pennsylvania, Inc. (Docket No. R-00994781) Restructuring Surrebuttal Testimony for the Pennsylvania Office of Consumer Advocate (October, 1999).

220. Rhode Island, Narragansett Electric Company et al. (Docket No. 2930) Merger Policy Testimony for the Rhode Island Department of Attorney General (November, 1999).

221. Delaware, Delmarva Power & Light Company (Docket No. 99-425F) Evaluation of Price Hedging Testimony for the Delaware Public Service Commission (December, 1999).

222. Rhode Island, Narragansett Electric Company et al. (Docket No. D-99-12) Merger Policy Testimony for the Rhode Island Department of Attorney General (December, 1999).

223. Pennsylvania, PECO Energy Company (Docket No. R-00994787) Restructuring Testimony for the Pennsylvania Office of Consumer Advocate (January, 2000).

224. Pennsylvania, PECO Energy Company (Docket No. R-00994787) Restructuring Surrebuttal Testimony for the Pennsylvania Office of Consumer Advocate (February, 2000).

225. Rhode Island, Providence Gas Company and Southern Union (Docket No. D-00-3) Merger Policy Testimony for the Rhode Island Division of Public Utilities and Department of Attorney General (May, 2000).

226. Philadelphia Gas Commission, Philadelphia Gas Works (2001 GCR Proceeding) Gas Procurement and Policy Testimony for the Public Advocate (August, 2000).

227. Rhode Island, Providence Gas Company (Docket No. 2581) Price Stability Plan Testimony for the Rhode Island Division of Public Utilities (August, 2000).

228. Pennsylvania, Philadelphia Gas Works (Docket No. R-00005654) Interim Base Rate Testimony for the Pennsylvania Office of Consumer Advocate (September, 2000).

229. Pennsylvania, Philadelphia Gas Works (Docket No. R-00005619) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (September, 2000).

230. New Jersey, Generic Provisional Rate Proceeding (Docket Nos. GR00070491, et al.) Provisional Rate Statement for the New Jersey Division of the Ratepayer Advocate (October, 2000).

231. New Jersey, Public Service Electric & Gas Company (Docket No. GR00070491) Levelized Gas Adjustment Clause Testimony for the New Jersey Division of the Ratepayer Advocate (November, 2000).

232. New Jersey, Generic Provisional Rate Proceeding (Docket Nos. GR00070491, et al.) Provisional Rate and Price Hedging Testimony for the New Jersey Division of the Ratepayer Advocate (December, 2000).

233. Rhode Island, Providence and Valley Gas Companies (Docket Nos. 1673 and 1736) Gas Price Mitigation Testimony for the Rhode Island Division of Public Utilities (January, 2001).

234. Delaware, Delmarva Power & Light Company (Docket No. 00-463F) Gas Price Hedging Testimony for the Delaware Public Service Commission (February, 2001).

235. Pennsylvania, Philadelphia Gas Works (Docket No. R-00006042) Base Rate and Policy Testimony for the Pennsylvania Office of Consumer Advocate (April, 2001).

236. Pennsylvania, Philadelphia Gas Works (Docket No. R-00006042) Base Rate and Policy Surrebuttal Testimony for the Pennsylvania Office of Consumer Advocate (May, 2001).