PGW Statement No. 1
Docket No. A-110550F0160
Witness: Paul R. Carpenter
9/23/05 Phila
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DIRECT TESTIMONY OF

PAUL R. CARPENTER

ON BEHALF OF
PHILADELPHIA GAS WORKS

Addressing the issue of vertical market power and whether the merged entity will have market power and incentive to use that market power to adversely affect the public interest and competition in electricity and natural gas markets and also addressing the remedial measures the Pennsylvania Public Utility Commission should consider to ensure competition and consistency with the public interest

Docket No. A-110550F0160

Joint Application of PECO Energy Company and Public Service Electric And Gas Company for Approval of the Merger of Public Service Enterprise Group Incorporated with and into Exelon Corporation

June 27, 2005

I. INTRODUCTION

Q. Please state your name, address and position.

A. My name is Paul R. Carpenter. I am a Principal and Vice Chairman of *The Brattle Group*, an economic and management consulting firm with offices in Cambridge, MA, Washington, DC, San Francisco, CA, and London, England. My office is located at 44 Brattle Street, Cambridge, Massachusetts 02138.

Q. What is your educational background and professional qualifications?

A. I am an economist specializing in the fields of industrial organization, finance and energy and regulatory economics. I received a Ph.D. in Applied Economics and an M.S. in Management from the Massachusetts Institute of Technology, and a B.A. in Economics from Stanford University. I have been involved in research and consulting on the economics and regulation of the natural gas, oil and electric utility industries in North America and abroad for over twenty years. I frequently have testified before federal, state and Canadian regulatory commissions, in federal court and before the U.S. Congress, on issues of pricing, competition and regulatory policy in these industries. Outside of North America, I have advised governments and regulatory bodies on the structure of their natural gas markets and the pricing of gas transmission services. These assignments have included testimony before the U.K. Monopolies and Mergers Commission and the Australian Competition Tribunal, and advice to the European Commission and the governments of, and regulators in, Greece, Ireland, the Netherlands, New Zealand and Australia.

I have been frequently called on to perform market power analyses for merger evaluations and in the context of antitrust lawsuits. For example, early in my career I was the principal expert witness in several of the seminal antitrust cases in the U.S. involving natural gas pipelines prior to the industry's restructuring under Federal Energy Regulatory Commission ("FERC") Orders No. 436 and 636. I also testified before the FERC and the California Public Utilities Commission on the merger of Enova and Pacific Enterprises (now Sempra Energy) regarding vertical market power issues. Recently, I testified before those bodies on the exercise of market power in western natural gas markets during the California Energy Crisis of 2000-2001 and its effects on the electricity market during the Crisis.

A copy of my resume, which includes a list of proceedings in which I have testified, is attached to this testimony as Appendix A.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by the Philadelphia Gas Works ("PGW") to evaluate the proposed Exelon/PSEG merger to determine whether it raises vertical market power concerns. More specifically, I have been asked to evaluate whether the merged entity would have market power in mid-Atlantic gas markets, and, if so, whether it would have the ability and incentive to use that market power to adversely affect competition in electricity and gas markets. PGW also asked me to suggest remedial measures the Pennsylvania Public Utility Commission ("Commission") should consider to ensure that the merged entity would not have the ability and incentive to take actions in mid-Atlantic gas markets that would harm competition in natural gas and electricity markets and thus ensure that the merger is consistent with the public interest.

I do not address horizontal electricity market power issues raised by the proposed merger in this testimony, although I am aware that others have evaluated those issues in submissions to the FERC.

Q. What have you concluded about the vertical impact of the proposed Exelon/PSEG merger in mid-Atlantic gas and electricity markets?

A. 1) The proposed merger of Exelon and PSEG raises significant vertical market power concerns. The merged entity would possess market power in the downstream electricity market represented by PJM East, and it would possess market power in the upstream market for delivered natural gas in the same geographic area. The degree of market power in the upstream gas market, as measured by the level and change in the HHI statistic, is sufficient to establish a presumption that the merger is "likely to create or enhance market power" under the FERC's standard for evaluating vertical mergers set out in Order No. 642.

2) Applicants' vertical market power analysis contains several errors. When corrected, Applicants' own analysis establishes that the merger fails the tests for lack of vertical market power. I calculate, conservatively, that the HHI in the PJM East delivered gas market rises from 1,469 to 1,942 with the merger – a change of over 470 points.

3) The merged entity will have the ability and incentive to raise the level and volatility of natural gas prices, and thus electricity prices, in PJM East. Its ability to raise the price of natural gas derives from the merged entity's control of substantial gas transportation rights, and its discretion and flexibility to draw on those rights depending on demand conditions in the market during particular days. The merged entity would control 2.6 billion cubic feet (Bcf) per day of delivery capability into the market, over 1.9 Bcf per day of which is held currently by PSE&G's unregulated affiliate PSEG Energy Resources and Trading ("PSEG ER&T"). When demand conditions are such that pipeline transportation capacity in the region becomes heavily utilized, the merged entity will potentially have a pivotal supplier role in the gas market.

4) The incentive of the merged entity to raise the price of gas derives from its substantial baseload power generation capacity that will remain in its possession after the proposed divestures. Since natural gas fired generation is "on the margin" during more than 50 percent of the peak hours in PJM East, an increase in the price of gas during those hours would directly translate into the market price of electricity to the benefit of the merged entity's baseload generation.

5) Existing regulations are not sufficient to protect against the potential for the exercise of market power by the merged entity, particularly since such a large proportion of its upstream holdings will be in the possession of an unregulated affiliate. The is no equivalent to the PJM Market Monitoring Unit for the gas markets relied on for power generation in PJM.

6) The vertical market power concerns raised by this merger are best remedied by eliminating the source of the market power in natural gas. This could be accomplished cleanly by requiring the divestiture of the regulated gas operations of PECO and PSE&G (including the contracts held by PSEG ER&T). An alternative remedy, requiring greater regulatory oversight, would require that the upstream gas assets held by PECO and PSEG ER&T be transferred to independent third parties (with regulatory oversight) to ensure that the ability of the merged entity to exercise market power in the natural gas market is separated from its incentive to exercise that power.

Q. Does Exelon and PSEG's proposed mitigation address these concerns?

A. No. Exelon and PSEG propose no mitigation to resolve vertical issues. The mitigation they propose to address horizontal (electricity market) concentration does not address the vertical issues I have identified.

Q. Is the current regulatory structure adequate to address these vertical concerns?

A. No. As I will explain in more detail below, conduct that may result in an increase in the price of natural gas, or an increase in gas price volatility, that might be engaged in by the merged entity in order to increase the price of electricity is very difficult to detect after the fact. This is particularly so in this case, because PSEG's natural gas assets (e.g., its gas supply and transportation contracts and storage rights) are currently in the hands of, and managed by, an unregulated affiliate PSEG ER&T,.

Q. What is PGW's interest in this proceeding?

A. PGW is the largest municipally owned gas utility in the U.S., serving nearly one half million customers in the City of Philadelphia who are significant consumers of both natural gas and electricity. PGW itself is an electricity customer of PECO Energy ("PECO"). Over the past four years, PGW's annual electricity expenditure has averaged over $2 million.

Q. Is PGW's position in this proceeding unusual?

A. Yes. PGW's position is unusual because of the situation in which it finds itself, particularly with respect to the make-up of its customer base and its financial position. PGW has more than $1 billion of debt outstanding and a very weak liquidity position, with unrestricted cash reserves representing less than one day's cash at particular times. Debt per customer is approximately $2,000, which is high compared to other municipal utilities. Short term borrowing is utilized to the maximum, leaving almost no flexibility to meet operating expenses should those costs increase. Annual revenues are approximately $850 million, but the demands of an aging infrastructure and a customer mix that cannot afford either a base rate or a gas cost rate increase severely restrict the Company's ability to tolerate any substantial cost increases.

I understand that PGW's financial condition has been the subject of several proceedings at this Commission. Although the financial condition of the company, in particular its cash flow, has improved, it remains particularly vulnerable. In addition, its customer base shows a very high percentage of residential customers and a correspondingly low percentage of commercial/industrial customers. A high percentage of the residential customers are at or below 150% of the federal poverty level or only slightly above. Finally, as a municipally-owned utility, it has no investors to provide capital in difficult financial times.

Q. You made reference to PGW's customer base. Why is that significant?

A. Residential customers make up 95% of PGW's customers and 67% of gas sales. PGW's customers have below average wealth levels and higher than average unemployment levels. Effective buying power is only 74% of the national average. One can expect that customers in that situation have difficulty paying heating bills that average $1,500 per year. To the extent that customers do not pay, they suffer and PGW suffers. In addition, it is clear that customers with such low incomes have difficulty absorbing any substantial cost increases in their budgets, so even if only electric bills increase, customers will still be stretched, will find it difficult to make ends meet, and will have more difficulty paying their PGW bills.

Even though PGW's customers have had the option to choose an alternative supplier since September 2003, no competitive suppliers are currently in operation in Philadelphia – perhaps in part due to the demographics of the customer base. Anything that increases the price and/or the volatility of the price of natural gas in the wholesale market will make it even more difficult for competitive suppliers to gain a foothold.

Q. Please describe how the remainder of your testimony is organized.

A. Section II discusses concerns presented by vertical mergers, and the Commission's standards for evaluating mergers that have potential impacts in both gas and electricity markets. Section III describes PSEG and Exelon's assets in mid-Atlantic gas markets. Section IV discusses the structural problems created by combining Exelon and PSEG's natural gas assets. Section V discusses the merged entity's ability to take actions that would increase mid-Atlantic gas prices or gas price volatility. Section VI discusses the incentives the merged entity would have to increase mid-Atlantic gas prices given its position in mid-Atlantic electricity markets. Section VII suggests remedies the Pennsylvania PUC should consider to mitigate the merged entity's vertical market power.

II. CONCERNS RAISED BY VERTICAL MERGERS

Q. What is a vertical merger?

A. A vertical merger is one that involves entities that have positions in two product markets where one product (e.g., natural gas) supplies or is an important input to the production of the second product (e.g., electricity). Exelon and PSEG's proposed merger is a vertical merger since it would combine Exelon's gas and electricity assets with PSEG's gas and electricity assets. It would create a merged entity that has a substantial position in both the gas and electricity markets in the PJM East region.

Q. What concerns do vertical mergers present?

A. The principal concern presented by a vertical merger is that the merged entity will use its market power in the first (input) product market to harm competition and raise prices in the second (output) product market.

The FERC has been concerned for some time about the potential for anticompetitive behavior arising from vertical mergers to adversely affect wholesale electricity markets, and I agree with the framework it has put forward for analyzing these issues. FERC Order No. 642 lays out its standards for reviewing vertical mergers.[1] FERC generally perceives three ways in which vertical market power may be exercised to adversely affect prices and output in electricity markets: (1) through foreclosure or raising rivals' costs, (2) by facilitating coordination, and (3) through regulatory evasion. In FERC's view, raising rivals' costs "can be accomplished through pricing, marketing and operational actions that raise the input costs of downstream competitors of the newly merged firm or by otherwise restricting such competitors' input supply."[2] However, a merged entity can have the ability and incentive to restrict rivals' access to inputs only if it can exercise market power in both upstream (e.g., gas) and downstream (electricity) markets.

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1 FERC Order No. 642, 93 FERC ¶ 61,164 (2000), *slip op.* at 91.

Q. Why should the Commission be concerned about this merger?

A. This Commission should be concerned with the impacts of the proposed merger on wholesale electric and gas markets, including vertical issues – the merged entity's ability and incentive to raise prices in gas markets in order to benefit in the electricity market. An exercise of vertical market power would deny customers the benefits of retail competition in both gas and electricity markets.[3] And, as I understand it, the Commission is obligated to consider whether a merger will affect competition in retail electricity and natural gas markets. Whether there is such a legal obligation or not, I believe that the merger will affect competition in a negative manner and will harm the public interest by denying customers and competitive suppliers the benefits of competition.

Q. What is your understanding of this Commission's obligation to review mergers that affect retail electricity and natural gas markets?

A. Section 2811(e) of the Public Utility Code (66 Pa. C.S. §2811(e)) requires the Commission to consider whether a proposed merger involving electric utilities or electric suppliers "is likely to result in anticompetitive or discriminatory conduct, including the unlawful exercise of market power, which will prevent retail customers from obtaining the benefits of a properly functioning and workable competitive retail electric market." The Commission is barred from approving proposed transactions that it views as likely to be harmful to retail electric markets except "upon such terms and conditions that it finds necessary to preserve the benefits of a properly functioning and workable competitive retail electricity market."

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[2] *Id., slip op.* at 91-92.

[3] Applicants acknowledge that competitive retail markets are tied to competition in wholesale markets. See Exhibit WHH-1 (Revised), page 14, lines 16-18: "Competitive retail markets rely on procurement of power from a competitive wholesale market, and, thus it is important from an ultimate customer perspective that the merger not increase market power in wholesale markets."

Similarly, Section 2210 of the Public Utility Code (66 Pa. C.S. §2210) requires the Commission to consider whether a proposed merger involving natural gas distribution companies or suppliers "is likely to result in anticompetitive or discriminatory conduct, including the unlawful exercise of market power, which will prevent retail gas customers from obtaining the benefits of a properly functioning and effectively competitive retail natural gas market." It bars the Commission from approving proposed transactions that it finds to be likely to be harmful to retail gas markets except "upon such terms and conditions as it finds necessary to preserve the benefits of a properly functioning and effectively competitive retail natural gas market."

As discussed above, these obligations to consider the competitive effects of this vertical merger on retail electricity and natural gas markets means the Commission should carefully examine its effects on wholesale markets.

Finally, the Supreme Court of Pennsylvania has held "that a certificate of public convenience approving a merger is not to be granted unless the Commission is able to find affirmatively that public benefit will result from the merger.... [T]he Public Utility Law requires that those seeking approval of a utility merger demonstrate more than the mere absence of any adverse effect upon the public [and] ... that the proponents of a merger demonstrate that the merger will affirmatively promote the 'service, accommodation, convenience, or safety of the public' in some substantial way."[4]

III. PSEG AND EXELON'S ASSETS IN MID-ATLANTIC GAS MARKETS

Q. What assets does PSEG hold in mid-Atlantic gas markets?

[4] *York et al., Appellants, v. Pennsylvania Public Utility Commission*, Supreme Court of Pennsylvania, 449 Pa. 136; 295 A.2d 825; 1972 Pa. LEXIS 358, October 4, 1972, pages 2-3.

A. PSEG's subsidiary Public Service Electric & Gas Company ("PSE&G") is a combined electric and gas utility with a service territory that covers 2,600 square miles in New Jersey and includes its six largest cities: Newark, Jersey City, Paterson, Elizabeth, Trenton and Camden.[5] PSE&G distributes gas to 1.7 million customers. Although all of PSE&G's customers have the ability to choose a competitive gas supplier, few of PSE&G's gas customers have left utility service.[6] PSE&G serves as the supplier of last resort in its service territory through its Basic Gas Supply Service ("BGSS").

PSE&G presently holds no interstate gas transportation capacity or storage capacity to meet its gas supply (BGSS or system balancing) obligations. Instead, PSE&G meets its gas supply obligations through a full requirements contract ("PSEG ER&T FR Contract") with its unregulated affiliate, PSEG ER&T.[7] PSE&G owns liquefied natural gas ("LNG") and liquid petroleum air gas ("LPG") peaking facilities located in its service territory with a withdrawal capacity of 289 MMcf/d during winter months.[8] PSE&G injects and withdraws from these peaking facilities at the direction of PSEG ER&T pursuant to the PSEG ER&T FR Contract.[9]

PSE&G distributes gas to 10 electric generating plants that are not owned by PSEG.[10] Two of these plants are merchant plants, with capacity of almost 940 MW. The other eight, with total capacity of 1,110 MW, are current or former Qualifying Facilities

5 Public Service Enterprise Group 2004 SEC Form 10-K, pages 4-6.

6 According to statistics for May 2005 made available by the New Jersey Board of Public Utilities (http://www.bpu.state.nj.us/energy/gasSwitchData.shtml), only 1% (11,441 out of 1,472,498) of PSE&G's residential customers and 6% (12,049 out of 194,100) of PSE&G's non-residential customers are purchasing gas from a competitive supplier.

7 The initial term of this contract expired March 31, 2004. PSE&G renewed it for an additional three year term ending March 31, 2007, at which point it will continue year-to-year unless cancelled with 12 months notice by either PSE&G or PSEG ER&T. See pages 9-10 of the PSEG ER&T FR Contract. PSE&G anticipates that there will be no changes to this contract as a result of the merger, except that the contract will be transferred from PSEG ER&T to the entity that assumes PSEG ER&T's role post-merger.

8 Public Service Enterprise Group 2004 SEC Form 10-K, page 29.

9 PSEG ER&T owns the gas injected into and withdrawn from these facilities. It compensates PSE&G for the costs of operating and maintaining the peaking facilities, plus a return on PSE&G's peaking facility investment. See pages 13-14 of the PSEG ER&T FR Contract.

10 Exhibit WHH-1 (Revised), pages 15 and 72.

("QF's") under contract with PSE&G. PSE&G also distributes gas to nine generating plants that are owned by PSEG.[11]

PSEG's subsidiary PSEG Power LLC is active in PJM East energy markets through three of its operating subsidiaries, PSEG ER&T, PSEG Nuclear LLC ("PSEG Nuclear"), and PSEG Fossil LLC ("PSEG Fossil"). As discussed further in Section V below, PSEG Nuclear and PSEG Fossil own significant electric generating assets in PJM, mainly in PJM East. PSEG ER&T purchases and markets the capacity and energy produced by PSEG Nuclear and PSEG Fossil. PSEG ER&T currently holds 1.6 Bcf/d of interstate transportation capacity into mid-Atlantic gas markets.[12] It also holds 82 Bcf of storage capacity with withdrawal rights of 940 MMcf/d during the winter.[13] Most of this transportation and storage capacity was transferred from PSE&G to PSEG ER&T in conjunction with the PSEG ER&T FR Contract. PSEG ER&T also controls the operation of PSE&G's peaking (LNG and LPG) assets. PSEG ER&T uses its gas market assets to meet its BGSS obligations with PSE&G, to supply gas to PSEG Fossil's gas-fired generation, and to make sales to third parties.

Q. What assets does Exelon hold in mid-Atlantic gas markets?

A. Exelon's subsidiary PECO is a combined electric and gas utility with an electric service territory of 2,000 square miles in southeastern Pennsylvania (including the City of Philadelphia) and a gas service territory of 1,900 square miles in southeastern Pennsylvania (surrounding, but not including the City of Philadelphia, which is served by PGW).[14] PECO's gas service territory is adjacent to PSE&G's. PECO delivers gas to 460,000 customers. Under the 1999 Pennsylvania Gas Choice and Competition Law, all of PECO's gas customers have the ability to choose a

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[11] These plants are: Bergen, Edison, Essex, Hudson, Kearny, Linden, Mercer, Sewaren, and Burlington. Each of these plants is eligible to be divested by Exelon/PSEG under the mitigation it proposed at FERC. See Exhibit No. WHH-1 (Revised), at Exhibit J-12.

[12] PSEG holds an additional firm transportation contract for roughly 70 MMcf/d on Transco for delivery from Tennessee's Riverdale delivery point in the mid-Atlantic region to other delivery points in the same region.

[13] Almost all of this storage capacity is located in the Appalachian region.

[14] Exelon Corporation 2004 SEC Form 10-K, page 4.

competitive supplier. A significant portion of PECO's total sendout is supplied by competitive suppliers.[15] However, PECO retains substantial provider of last resort supply obligations. In particular, almost all of PECO's residential customers continue to purchase gas from the utility.[16] PECO holds roughly 370 MMcf/day of interstate capacity into mid-Atlantic gas markets. It also holds 21 Bcf of storage (with a withdrawal capacity of 260 MMcf/day) to meet its supply obligations.[17] It operates an LNG and an LPG peaking facility on its distribution system with total daily sendout capability of 182 MMcf/d.[18]

PECO distributes gas to three electric generators that are not affiliated with Exelon, with total capacity of almost 200 MW.[19] These electric generators are either industrial facilities that consume most of the power they produce, or dual-fueled. PECO also delivers gas to three facilities owned by Exelon, Cromby, Eddystone and Fairless Hills.[20]

PECO's affiliate Exelon Generating Company, LLC ("ExGen") is active in PJM East electricity markets, as described in more detail in Section V below. PECO transferred its electric generating plants to ExGen in 2001. PECO meets almost all of its supply obligations through a full requirements contract with ExGen ("ExGen/PECO FR Contract").[21] ExGen's subsidiary Power Team markets ExGen's energy generation,

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[15] According to Exelon Corporation's 2004 SEC Form 10-K (page 10), 32% of PECO's annual throughput is supplied by competitive suppliers.

[16] See Pennsylvania Gas Shopping Statistics, April 1, 2005, Pennsylvania Office of Consumer Advocate. Only 0.4% (1,777 out of 425,059) of PECO's residential customers are purchasing gas from a competitive supplier.

[17] In addition, PECO holds a firm transportation contracts on Texas Eastern with receipt rights within PJM East at PECO's Eagle station, and delivery rights within PJM East at PECO's Planebrook, Hershey's Mill, and Brookhaven stations. This contract has capacity of roughly 117 MMcf/d. It allows PECO to move gas across its distribution system by utilizing Texas Eastern, but it does not allow PECO to bring additional supplies into PJM East. See Texas Eastern's March 4, 1997 filing in FERC Docket No. CP97-276. Most (16 Bcf) of PECO's storage capacity is located in the Appalachian region.

[18] See Section 22 of PECO's 2005 1307(f) filing, provided in response to Request OCA VII-4.

[19] Exhibit WHH-1 (Revised), pages 15 and 72.

[20] See Response to Request PGW-IV-17. Cromby, Eddystone and Fairless Hills are also eligible to be divested under the mitigation proposed by Exelon/PSEG at FERC. *Id.*, at Exhibit J-12.

[21] Exelon Corporation SEC Form 10-K, page 8.

and satisfies ExGen's obligations under the ExGen/PECO FR Contract.[22] ExGen does not control assets in PJM East gas markets. The only interstate capacity it holds in Northeast gas markets is roughly 25 MMcf/d on Iroquois Gas Transmission System.[23] Another ExGen subsidiary, Exelon Energy Company, is a retail gas and electricity supplier. It does not hold firm transportation capacity with delivery rights in PJM East.[24]

Q. How do Exelon and PSEG plan to combine their natural gas operations post-merger?

A. Exelon and PSEG do not currently plan to combine the gas procurement operations of PECO and PSE&G (which is currently performed by PSEG ER&T),[25] although to my knowledge they have made no commitment not to do so. However, Exelon and PSEG do plan to combine their trading operations (Power Team and PSEG ER&T) in Pennsylvania, where Power Team is currently located.[26] This will combine Exelon's significant electricity trading operation with the significant gas and electricity trading operations of PSEG ER&T.

IV. GAS MARKET STRUCTURAL PROBLEMS CREATED BY THE PROPOSED MERGER

Q. How do you evaluate whether there are gas market structural problems created by the proposed merger?

A. The Applicants have submitted an analysis by Dr. William Hieronymus, testifying on behalf of PECO, in this proceeding that was meant to satisfy FERC's vertical market power test.[27] FERC uses a two-prong test to determine whether a vertical merger

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22 *Id.*, page 11.
23 See Response to OCA VII-1(a).
24 See Response to COP Request 1-73, Attachment 3.
25 See PECO Energy Company and Public Service Electric and Gas Company's response to Request OCA Set II Question 1. But, see also confidential response to OCA Request VII-4 (Attachment 3, page 8).
26 See PECO Statement No. 1-Direct Testimony of Denis P. O'Brien, page 4, lines 12-13.
27 Exhibit WHH-1 (Revised), pages 69-75.

creates a combined entity with the incentive and ability to raise its rivals' costs.[28] It requires a calculation of a Herfindahl-Hirschman Index ("HHI")[29] for relevant downstream markets with electric generators assigned to their upstream suppliers. FERC suggests that downstream markets that are highly concentrated (with an HHI statistic that is greater than 1,800) are "conducive to the exercise of market power." FERC also requires a calculation of an HHI for relevant upstream markets. Again, FERC suggests that upstream markets that are highly concentrated (with HHIs greater than 1,800) are vulnerable to market power exercise. If both upstream and downstream markets are highly concentrated, FERC requires applicants to either provide additional information regarding their ability and incentive to raise rivals' costs, or propose specific mitigation measures that would eliminate their vertical market power.

I use the second prong of FERC's vertical market power test to determine whether upstream gas markets are concentrated post-merger. Dr. Hieronymus concedes that even with Exelon and PSEG's proposed electricity market mitigation, relevant downstream (electricity) markets are highly concentrated after the merger.

Q. What is the relevant upstream product market for evaluating potential vertical structural problems created by the proposed Exelon/PSEG merger?

A. The relevant upstream product market is delivered natural gas.

Q. What is the relevant geographic market?

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28 FERC Order No. 642, *slip op.* at 102-115.

29 The Herfindahl-Hirschman Index ("HHI") for a market is the sum of the squared market shares of each firm competing in the market. For example, for a market with two equally sized competitors, the HHI is 5,000 (=$50^2 + 50^2$). It is superior statistic to a simple market share because it incorporates both the single firm market share and the distribution of shares among firms in the market.

A. PJM East[30] is an appropriate geographic market. It is the geographic market where there is the most overlap in Exelon and PSEG's electricity and natural gas assets. It is also the geographic market the Applicants adopt for the vertical analysis they submitted. Dr. Hieronymus states that the PJM Market Monitor has identified constraints for imports of power into PJM East, and that electricity prices in PJM East are often separated from prices in other regions of PJM.[31] Therefore, it is appropriate to include only generators in PJM East as alternatives to generation owned by or served by Exelon and PSEG.[32]

Four major interstate pipelines deliver gas to electric generators in PJM East: Transcontinental Gas Pipeline ("Transco"), Texas Eastern Transmission ("Texas Eastern"), Columbia Gas Transmission Corp. ("Columbia") and Tennessee Gas Pipeline ("Tennessee"). Firm transportation capacity on these pipelines into PJM East represents reasonable alternatives to Exelon and PSEG's delivered supplies.

Q. Would the PJM East delivered gas market be highly concentrated if PSEG and Exelon merge?

A. Yes. As shown in Table 1 below, I calculate that the HHI in the PJM East delivered gas market in 2006 would exceed 1,800 if PSEG and Exelon merge. Therefore, the PJM East gas market would be highly concentrated post-merger. I find that the proposed Exelon/PSEG merger increases the HHI in this market by over 470.

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30 PJM East consists of New Jersey, Delaware, and counties in the eastern portions of Pennsylvania and Maryland.

31 Exhibit WHH-1 (Revised), page 33.

32 It may also be appropriate to look at smaller geographic markets within PJM East in order to examine potential vertical impacts of the proposed Exelon/PSEG merger. It could be that the merged entity would have the ability to create congestion on electric transmission interfaces within PJM East through control of its own electric generating units, or gas-fired units that it serves, and that it could benefit from this congestion on its electricity sales. However, due to time constraints in preparing this testimony, I have not analyzed smaller geographic markets within PJM East.

Table 1
Impact of the Proposed Exelon/PSEG Merger
on Concentration in the PJM East Delivered Gas Market

	Pre-Merger			Post-Merger		
Participant	Contracts (MMcf/d)	Market Share	HHI	Contracts (MMcf/d)	Market Share	HHI
Exelon/PSEG	-	-	-	2,035	40%	1,585
PSEG	1,663	33%	1,059	-	-	-
New Jersey Resources	686	13%	180	686	13%	180
Exelon	372	7%	53	-	-	-
Pepco	311	6%	37	311	6%	37
Philadelphia Gas Works	295	6%	33	295	6%	33
UGI Corp	256	5%	25	256	5%	25
NUI Corporation	250	5%	24	250	5%	24
South Jersey Industries	230	4%	20	230	4%	20
NiSource Inc	215	4%	18	215	4%	18
Williams Energy	116	2%	5	116	2%	5
Dominion	97	2%	4	97	2%	4
Sunoco	93	2%	3	93	2%	3
PPL	74	1%	2	74	1%	2
WGL Holdings	68	1%	2	68	1%	2
Keyspan	55	1%	1	55	1%	1
Southern Union Company	48	1%	1	48	1%	1
Philadelphia Authority For Industrial Development	35	1%	0	35	1%	0
Amerada Hess Corporation	34	1%	0	34	1%	0
Others	214	4%	1	214	4%	1
	5,112	100%	1,469	5,112	100%	1,942

According to the FERC's standard set out in Order No. 642, if the post-merger HHI exceeds 1,800 and the change in the HHI exceeds 100, "it is presumed that the merger is likely to create or enhance market power."[33]

Q. Dr. Hieronymus found that the post-merger delivered gas market was not highly concentrated. Why does your result differ from his?

A. I used Dr. Hieronymus' analysis as a starting point,[34] but then made several corrections to what are clearly errors in his analysis. These corrections are: (1) I excluded contracts that deliver into the Algonquin pipeline (largely held by New York and New England LDC's) for ultimate delivery outside of PJM East, (2) I included contracts that appear to have been excluded from Dr. Hieronymus' analysis,

[33] FERC Order No. 642, *slip op.* at 70 fn. 62.

even though they are in his relevant market and are in effect in 2006, and (3) I excluded contracts that Dr. Hieronymus included that have receipt rights *only* in PJM East, and therefore cannot represent alternatives to capacity held by the Exelon and PSEG into PJM East.[35] Some of these corrections to Dr. Hieronymus' work increase the post-merger HHI while others decrease the statistic.

Q. **How does Dr. Hieronymus calculate concentration in interstate transportation markets, and why were your corrections necessary?**

A. Dr. Hieronymus first used the EIA's database of pipeline capacity across state borders to estimate pipeline capacity into PJM East. He then used Index of Customers reports filed at FERC for Transco, Texas Eastern, Columbia and Tennessee to identify firm transportation rights that are in effect in 2006, and have delivery rights into PJM East. When he aggregated PJM East delivery rights, two pipelines (Transco and Tennessee) had total PJM East delivery rights that were less than their capacity into PJM East. So, Dr. Hieronymus assigned the remaining capacity on these two pipelines to their owners, Williams Energy and El Paso. Total PJM East delivery rights on the two remaining pipelines, Texas Eastern and Columbia, exceeded their capacity into PJM East. Therefore, Dr. Hieronymus prorated the delivery rights of small suppliers so that his total PJM East delivery rights equaled his total PJM East pipeline capacity.

When he identifies interstate delivery rights into PJM East, Dr. Hieronymus ignores the fact that Texas Eastern most significantly, but also Transco, Tennessee and Columbia, make deliveries in PJM East into the Algonquin pipeline for ultimate delivery in New England and New York. Including these Algonquin delivery rights in PJM East is inappropriate. They are largely committed to serving other markets.[36]

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[34] See Exhibit WHH-1 (Revised), pages 71-73 and Exhibits J-15 and J16 for Dr. Hieronymus' concentration analysis. See also his description of this analysis in Exhibit J-4, pages 12-15.

[35] As explained further below, I also removed a contract held by PECO on Texas Eastern and a contract held by PSEG on Transco that have receipt point rights only within PJM East.

[36] Dr. Hieronymus suggests in Exhibit WHH-2 (page 44) that since Portland Natural Gas Transmission System ("PNGTS") and Maritimes and Northeast ("M&NE") expanded into New England, capacity that traverses PJM East to deliver to New England is more likely to serve PJM East. His argument is

Therefore, they cannot offer a reasonable alternative to Exelon and PSEG's PJM East capacity. Including Algonquin delivery rights in PJM East is also inconsistent with Dr. Hieronymus' own methodology. He does not include any other upstream (New York or New England) delivery rights in his PJM East market. Yet, he is treating what is in effect a custody transfer that occurs in PJM East (mainly) between Texas Eastern and Algonquin as a delivery into PJM East.[37]

I correct Dr. Hieronymus' HHI calculation to exclude delivery rights into Algonquin from my HHI calculation. Table 2 shows the Algonquin delivery rights that I have excluded.

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simplistic, and inconsistent with actual developments in New England gas markets. PNGTS has total capacity of 230 MMcf/d. M&NE has capacity of roughly 440 MMcf/d. However, substantial deliverability decreases from the Sable Island production area mean that deliveries to New England on M&NE are significantly less than M&NE's capacity. M&NE's load factor in 2004 was less that 50% (220 MMcf/d) due to production problems at Sable Island (see "2004 State of the Markets Report," FERC Office of Market Oversight and Investigations, June 2005, page 173). PNGTS imported only 47 Bcf, or 130 MMcf/d, from Canada during 2004 ("2004 State of the Markets Report," page 171). Both PNGTS and M&NE came on-line in 1999. According to the EIA's *Natural Gas Annual*, annual gas consumption in New England grew from 1,820 MMcf/d on average in 1997-1999 to 2,230 MMcf/d in 2004, an increase of 410 MMcf/d. So, it does not follow that the entry of PNGTS and M&NE has unloaded other pipeline capacity to New England.

[37] Dr. Hieronymus also includes two contracts on Columbia with total delivery capacity of roughly 15,000 MMcf/d that are for service under Columbia's Off-Peak Firm Transportation Service ("OPT"), and can be interrupted by Columbia on as many as 60 days during winter months.

Table 2
Algonquin Delivery Rights

Participant	LDC Subsidiaries Holding Capacity into Algonquin	Delivery Rights into Algonquin (MMcf/d)
Keyspan	Boston Gas Company, Colonial Gas Company	196
Southern Union Company	New England Gas Company, Providence Gas Company, North Attleboro Gas Company, Bristol & Warren Gas Company	- 130
NSTAR	NSTAR Gas Company	105
Northeast Utilities	Yankee Gas Services Company	86
Energy East	Connecticut Natural Gas, Southern Connecticut Gas	75
Northeast Energy Associates		49
NiSource Inc	Bay State Gas, Northern Utilities	43
BP-Amoco		39
CH Energy Group	Central Hudson Gas & Electric	32
Consolidated Edison	Consolidated Edison Company, Orange & Rockland Utilities	30
UGI Corp		19
NRG Energy Inc.		19
Dominion	Dominion Peoples	15
Duke/Engage America		11
New Jersey Resources	New Jersey Natural Gas Company	7
City of Norwich, CT Dept. of Public Utilities	City of Norwich, CT, Department of Public Utilities	5
Tenaska		5
Amerada Hess Corporation		5
Town Of Middleborough	Middleborough Gas & Electric Department	1
WGL Holdings		1
Total		871

As Table 2 shows, the entities that hold Algonquin delivery rights are largely New England and New York LDCs. This reinforces my point above that these Algonquin delivery rights are not properly in Dr. Hieronymus' PJM East market, because they are committed upstream and cannot offer an alternative to capacity held by the merged entity in PJM East.

Dr. Hieronymus inappropriately excludes certain contracts from his upstream market analysis, which I include in my HHI calculation. These excluded contracts include several contracts on Transco, including a contract held by PGW, and certain contracts held by PSEG and PECO, that appear to have been treated by Dr. Hieronymus as if they expire in 2005 -- when they do not.[38] They also include delivery rights on Texas

[38] The contracts held by PECO that are excluded by Dr. Hieronymus are two contracts on Texas Eastern, (contacts 800231 and 800407) with a total capacity of almost 82 MMcf/d. I used PECO's 2005 1307(f) filing made with this Commission and also provided in discovery in this proceeding to verify that these contracts have evergreen roll-over rights and should not be treated as if they expire before 2006. The contract held by PSEG that is excluded by Dr. Hieronymus is a contract on Transco with

Eastern and Columbia that are in PJM East, but which Dr. Hieronymus treats as if they were outside his relevant market.

Finally, I exclude contracts that only have receipt rights in PJM East.[39] In recent years, there have been several capacity expansions that have added laterals within PJM East.[40] These expansions receive gas from mainline delivery points in PJM East and deliver this gas in the same market. There have also been expansions that add capacity between two mainline points within PJM East.[41] In both of these cases, this new capacity cannot be considered to create an alternative to capacity held by Exelon and PSEG.

I do not make an adjustment for market size in calculating an HHI for PJM East. Using the EIA database of capacity across state borders (as Dr. Hieronymus does) is difficult for a market like PJM East that does not have a boundary along state lines. Moreover, it overestimates capacity into PJM East, because it counts both capacity into PJM East and capacity into markets that are upstream of PJM East. Depending on how an adjustment for market size is made, it could increase the post-merger HHI significantly.[42] Therefore, I consider the HHI results that I have reported above to be conservative.

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capacity of roughly 35 MMcf/d. I used data provided by PSEG in discovery to verify that this contract has evergreen roll-over rights and should not be treated as if it expires before 2006.

39 I exclude two contracts held by PECO and PSEG that have receipt points only in PJM East: PSEG's contract for approximately 70 MMcf/d from the Tennessee/Transco interconnection at Riverdale, and PECO's contract for approximately 117 MMcf/d on Texas Eastern from PECO's Eagle Station.

40 For example, Texas Eastern applied for a certificate to construct the Columbia Liberty Lateral project at FERC in 2000 (FERC Docket No. CP00-404). It added capacity on Texas Eastern from PECO's Eagle station to the Liberty plant in Delaware County, PA. FERC stated when it certificated the project that Liberty's owners intended to rely on capacity release, interruptible capacity, or market area purchases to procure gas on the Texas Eastern mainline. Similar projects within PJM East include Columbia's Rock Springs Lateral (FERC Docket No. CP02-142), and Texas Eastern's expansion of its Philadelphia Lateral (FERC Docket No. CP95-76).

41 For example, Transco's Central New Jersey expansion (FERC Docket No. CP04-396) provides service within New Jersey to South Jersey Gas.

42 I note that Direct Energy Serivces LLC filed at the FERC an analysis of concentration in the PJM East gas market performed by Dr. George E. Briden. Dr. Briden made an adjustment for market size that, unlike Dr. Hieronymus' calculation, accounted for capacity "traversing" PJM East to deliver to upstream markets. Dr. Briden calculated an HHI for the PJM East gas market of 2,676 points. See

V. THE MERGED ENTITY'S ABILITY TO INCREASE GAS PRICES

Q. In what ways could the combined Exelon and PSEG use its market power in upstream natural gas markets to affect the price of gas?

A. As described above, Exelon and PSEG have flexibility to draw on their substantial gas transportation and LPG/LNG assets to meet the demands of their retail customers. This amounts to a combined 2.6 Bcf/d of delivery capability into the market, over 1.9 Bcf/d of which is held by PSE&G's unregulated affiliate PSEG ER&T. On most days of the year, this capability greatly exceeds the retail gas demands that the merged entity will be required to meet, including storage injection requirements. This means that the merged entity will have the discretion to make third-party sales, or release transportation capacity into the wholesale market, or not make such sales and releases, on any given day. When demand conditions are such that pipeline transportation capacity in the region becomes heavily utilized, the merged entity will potentially have a pivotal supplier role in the gas market. Its decisions concerning the use, or lack of use, of the gas assets it controls would affect the level and volatility of the price of gas.

Q. If the merged entity were to decide to withhold gas transportation capacity from the market by not using or releasing it, wouldn't that capacity become available to the market on an interruptible basis?

A. In theory, yes. But interruptible transportation is a very poor substitute for firm transportation capacity, particularly during periods when gas-fired power generator demands for gas are high, or for example, during the winter when the available interstate pipeline capacity is heavily utilized by firm-capacity holders. During such periods, it is risky for gas-fired power generators, who have bid and committed output

Motion to Intervene and Protest of Direct Energy Services LLC, April 11, 2005, FERC Docket No. EC05-43.

from their plants into the electricity market, to rely on a gas supply that could be interrupted for any number of reasons.

Q. You mentioned that the merged entity would have the ability to increase the volatility of the price of gas in addition to the price level. How could that be accomplished?

A. A combined Exelon/PSEG would be in a position to increase gas price volatility through the discretionary use, for example, of selected storage (and LPG/LNG) injection and withdrawal strategies at particular locations. Decisions to accelerate or decelerate withdrawals during the winter, for example, in lieu of using the merged entity's pipeline transportation capacity to meet retail requirements or make off-system sales could cause rapid movements in prices (both upward and downward). Such volatility would be beneficial to Exelon/PSEG's unregulated power and gas trading arm that has physical and financial positions that profit from increased price volatility.

Q. Are there existing federal and state regulations that prohibit these forms of market manipulation?

A. Yes, again in theory. But such conduct is very difficult for regulators to detect after the fact unless the regulators are collecting the right data, are carefully monitoring the actions of the company, and are able to distinguish between price movements caused by actions of the company and price movements that are the result of the complexities of market forces. Moreover, because of the unregulated status of PSEG ER&T, the New Jersey BPU does not currently concern itself with how ER&T manages the gas assets under its control in order to meet the BGSS requirements contract ER&T holds with PSE&G. If the BPU suspected that there was a problem with the way ER&T was using the pipeline or storage capacity it controls to meet the PSE&G

requirements, it would have to file a complaint at the FERC.[43] The ability to file a complaint at the FERC is not a sufficient remedy for a vertical market power problem that is implicated by a merger.

VI. THE MERGED ENTITY'S INCENTIVES TO INCREASE GAS PRICES

Q. How would the merged entity benefit in electricity markets from an increase in PJM East gas prices?

A. The proposed Exelon/PSEG merger combines Exelon's substantial baseload generation assets in PJM with PSEG's generation assets. See Table 3.

Table 3
Exelon and PSEG Electric Generation in PJM (MW)

Region	Fuel Type	Exelon	PSEG	Exelon + PSEG	Exelon + PSEG After Proposed Mitigation
PJM East	Nuclear	3,833	2,324	6,157	6,157
	Hydro/Landfill Gas	608	200	808	0 - 808
	Coal	725	1,256	1,981	0 - 1,431
	Gas	6	5,506	5,512	3,162 - 5,512
	Oil and Gas/Oil	1,970	835	2,805	1,805 - 2,805
PJM Central	Nuclear	1,898	1,112	3,010	3,010
	Hydro	1,070	9	1,079	1,079
PJM West and Far West	Hydro	-	-	-	-
	Coal	709	771	1,480	1,480
	Oil	5	5	9	9
PJM (ECAR)	Gas	-	1,946	1,946	1,946
PJM (MAIN)	Nuclear	10,007	-	10,007	10,007
	Purchases	5,333	-	5,333	5,333
	Total PJM	26,164	13,963	40,127	37,227

Source: Exhibit WHH-1 (Revised), Exhibit J-3. Excludes 177 MW of NUGs committed to Exelon in PJM East and PJM Central.

Table 3 reflects mitigation (actual but not virtual divestiture) Exelon and PSEG have proposed in their application before the FERC. In their February 4, 2005 FERC merger filing, Exelon and PSEG propose to divest 1,900 MW of mid-merit capacity

[43] *Order Approving Transfer of Contracts*, In the Matter of the petition of Public Service Electric and Gas Company's Proposal to Transfer its Rights and Obligations Under Its Gas Supply and Capacity Contracts and Operating Agreements to an Unregulated Affiliate and Other Relief, BPU Docket No. GM00080564, 17 April 2002, at page 10

(with a requirement that at least 550 MW will be coal capacity, and 1,200 MW will have a marginal cost that is less than $55/MWh), and 1,000 MW of peaking capacity, all in PJM East. Exelon and PSEG also propose to "virtually divest" 2,400 MW of nuclear capacity in PJM East and 200 MW in PJM outside of PJM East. This virtual divestiture will be accomplished either via annual auctions of three-year entitlements, or via 15-year contracts. Exelon and PSEG offered in their May 9, 2005 FERC filing to divest an additional 200 MW of capacity in PJM East that has marginal cost greater than $55/MWh, and an additional 900 MW of capacity elsewhere in PJM.[44] This additional divestiture commitment is contingent upon the FERC's approval of the Exelon/PSEG merger without a hearing. As of the writing of this testimony, the FERC has not decided whether to hold hearings on the merger. Therefore, I have not included this contingent divestiture in Table 3. Even if it were included, this additional divestiture would not substantially change the merged entity's incentives since it would retain control over sufficient baseload generating capacity in PJM East to benefit significantly from increased PJM East gas prices and gas price volatility.

Data provided in Dr. Hieronymus' workpapers suggests that gas was on the margin during almost 40% of all hours in 2004 in PJM East, and during 60% of peak hours.[45] When gas is on the margin in PJM East, an increase in the PJM East gas price increases the PJM East electricity price, which benefits the merged entity through increased profits on its baseload capacity.

One strategic reason for the proposed merger is to increase the output of PSEG nuclear plants.[46] Currently, PSEG is exposed to spot power purchases to cover its BGS load obligations when PSEG's nuclear units are down or operating below

[44] Exhibit No. WHH-2, pages 46-47.

[45] This is slightly higher than estimates made by other sources. FERC's OMOI projected in its "2003 Summer Energy Market Assessment" that gas would be on the margin during 48% of peak hours in MAAC. See "Energy Market Assessment," Staff Report by the FERC Office of Market Oversight and Investigations, July 2003. The PJM Market Monitor calculated that gas units were on the margin during 31% of all hours in 2004 in PJM. See "2004 State of the Market Report," PJM Market Monitoring Unit, page 70.

[46] *See "Project Sue, Board of Directors Update," October 26, 2004, page 6, provided in response to* Request OCA VI-5.

capacity. Thus, PSEG is exposed to electricity purchases that rise in price as gas prices increase. Post-merger, Exelon and PSEG expect to increase the efficiency of PSEG's nuclear plants, decreasing PSEG's exposure to gas-price-sensitive market purchases.

Q. Would PECO or PSEG be exposed to increases in the price of natural gas in a way that would nullify the incentives to exercise vertical market power?

A. No. PECO's costs of gas are treated as a pass-through to its ratepayers, so an increase in the price of gas would not affect its profitability. PSE&G's situation is a bit more complex, because of the fact that its gas assets are held by PSEG ER&T. PSEG ER&T is at risk for the recovery of the cost of the assets that were transferred to it to provide service to commercial and industrial customers.[47] In this respect, an increase in the price of gas would actually benefit PSEG ER&T by reducing its cost recovery risk of holding those contracts. PSE&G's margins on the BGSS service it provides to residential customers would not be adversely affected by an increase in the price of gas.

Q. Does the ExGen/PECO FR Contract nullify the merged entity's incentives to increase gas prices?

A. No, it does not. This Commission cannot rely on a contract that expires at the end of 2010 to blunt the merged entity's incentive to increase gas prices: In fact, the Commission is already planning for how Pennsylvania electric distribution companies will provide for default service at the end of their transition periods. Exelon has proposed an auction to procure power to meet PECO's provider of last resort supply

[47] *Order Approving Transfer of Contracts,* In the Matter of the petition of Public Service Electric and Gas Company's Proposal to Transfer its Rights and Obligations Under Its Gas Supply and Capacity Contracts and Operating Agreements to an Unregulated Affiliate and Other Relief, BPU Docket No. GM00080564, 17 April 2002, at page 13.

obligations after 2010.[48] Post-merger, Exelon would have the ability and the incentive to increase the PECO auction price by increasing the price of gas in PJM East. Exelon would also have the ability and incentive prior to 2011 to deter entry by gas-fired generators into PJM East by increasing the level and volatility of PJM East gas prices.

Q. Dr. Hieronymus states that the merged entity will maintain a 90% hedge ratio. Will this remove its incentive to increase gas prices?

A. No. Exelon provided more information about this commitment in the Response to OCA V-25. According to this data response, Exelon has a risk management policy to sell (via load obligations, sales of standard products, and options) 90% of its economic generation twelve months in advance. Twelve months in advance is not a long-term commitment. Having 90% of its generation hedged in this way is not the same as saying this 90% will not benefit from increased gas prices. It may, depending on when it is re-contracted. Thus, the merged entity will still have an incentive to take actions in gas markets that benefit when it locks in its forward electricity sales.

Q. How does Exelon and PSEG's "virtual divestiture" of nuclear capacity in PJM East affect the merged entity's incentive to increase gas prices?

A. Exelon and PSEG's "virtual divestiture" has an effect similar to its 90% hedge ratio. If the merged entity virtually divests nuclear capacity in annual auctions for three-year entitlements, it will benefit via the auction price from actions it takes that increase PJM East gas prices.

Q. What else do the Applicants assert about the vertical impacts of the proposed Exelon/PSEG merger?

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[48] Comments of the Exelon Companies to the December 16, 2004 Proposed Rulemaking Order, April 27,

A. Dr. Hieronymus describes several factors that he claims prevents, or makes it more difficult for, the merged entity to exercise vertical market power.[49] These factors are: (1) PECO and PSE&G's distribution systems serve a relatively small amount of unaffiliated electric generation; (2) Pennsylvania and New Jersey regulate PECO and PSE&G's distribution tariffs, and have imposed open access requirements on PECO and PSE&G; (3) new generation in PJM East could bypass PECO and PSE&G's distribution systems and connect directly to an interstate pipeline; (4) PECO's gas transportation assets are committed to meeting its retail customer load; (5) the merged entity could not withhold its firm transportation rights because this would simply increase the amount of non-firm capacity available to the market; and (6) the merged entity must comply with affiliate conduct codes in Pennsylvania and New Jersey, and FERC Order No. 2004.

Q. How do you respond to each point?

A. (1) The amount of unaffiliated generation served by the distribution systems of PECO and PSE&G minimizes only one form of potential anticompetitive behavior, and not the potential behavior that is the focus of my analysis in this case. That is, the ability and incentive of the merged entity to raise rival generator's costs in this case derives from its ability to raise the wholesale price of gas generally in PJM East, which differentially benefits its baseload generation relative to competitors' gas-fired units (including those units that are divested).

(2) The regulation of the tariffs and open access requirements placed on PECO and PSE&G as distributors is irrelevant to the vertical market power I have analyzed. This market power derives from the upstream contractual position held by the combined entities, and not their regulated distribution systems.

2005, Docket No. L-00020169.

[49] Exhibit WHH-1 (Revised), pages 15-16.

(3) Whether or not new generation in PJM East could bypass PECO and PSE&G's distribution systems is also irrelevant, because the combined entity has the ability and incentive to raise gas prices for all gas-fired plants in PJM East.

(4) While PECO's gas transportation assets may be committed (in a regulatory sense) to meeting its retail customer load, on most days it holds substantially more capacity (including storage and LNG/LPG) than is required to meet that load. Thus, and particularly when combined with the assets held by PSEG ER&T, the combined entity will have substantial discretion in how it uses those assets.

(5) As I described above, non-firm or interruptible capacity that might be made available as a result of episodic capacity withholding is not a substitute for firm gas supply that a gas-fired plant requires to meet its generation commitments. This is a lesson that was learned painfully during the summer of 2000 in California, when interruptible transportation failed to substitute for the firm capacity that was withheld from the market on the El Paso Natural Gas pipeline.

(6) The affiliate conduct codes Dr. Hieronymus refers to would not in any way diminish the vertical market power of the merged entity. Even assuming that these codes apply to communications between unregulated affiliates such as PSEG ER&T and Exelon's gas and power trading arm, violations of these rules are difficult to detect and enforce after the fact.

VII. REMEDIAL MEASURES

Q. What potential remedies are available to eliminate the vertical market power risk posed by the merger?

A. There are two basic classes of potential remedies: 1) remedies that eliminate the *incentive* to exercise vertical market power created by the merger, and 2) remedies that eliminate the *ability* of the merged entity to exercise that power. In my opinion the second of these two alternatives is preferable in this case. As to the first, the divestiture proposed by the Applicants before the FERC (including some gas-fired generation) does not solve the problem, as demonstrated above. Even with the additional divestiture of substantial baseload generating plants, including nuclear units, the combined entity would still have an incentive to raise gas and power prices and price volatility to benefit its unregulated trading operations. Furthermore, continued regulatory scrutiny would be necessary to ensure that the merged entity would not be able to gain future positions in electricity markets and trading that would benefit from the exercise of vertical market power. The preferred approach to remedy the problem is to eliminate the *ability* of the combined entity to exercise vertical market power.

Q. What remedies are available to eliminate the ability to exercise vertical market power in this case?

A. Both structural and conduct remedies are available. By structural, I am referring to remedies that involve the transfer or divestiture of natural gas assets that are the source of the market power. Conduct remedies would include enhanced regulatory rules and codes of conduct that would help prevent the exercise of market power. Structural remedies are to be preferred, when available, because conduct remedies are frequently difficult and costly to enforce by the relevant regulators – particularly in this case where there are multiple regulatory authorities involved.[50]

Q. What are the structural remedies that you recommend in this case?

A. The cleanest and easiest to enforce structural remedy would be to require as a condition for approval of the merger the divesture of PECO Gas and PSE&G's gas

[50] See Section III.A. of the "Antitrust Division Policy Guide to Merger Remedies," U.S. Department of Justice, Antitrust Division, October 2004.

distribution company (including the gas assets held and managed by PSEG ER&T described above). This remedy would, by definition, eliminate the vertical problem.

A second, more targeted approach is also one that would require greater regulatory supervision going forward. This remedy would require that the gas assets (upstream transportation contracts and storage rights) held by PECO and PSEG be placed in the hands of third parties that are independent of the merged entity and subject to oversight by Pennsylvania and New Jersey regulators, respectively. In the case of the assets currently managed by its unregulated subsidiary PSEG ER&T, putting these assets in independent third party hands with regulatory oversight would ensure that the ability to exercise market power is mitigated and separated from the incentive to exercise that power.

Q. Does this complete your direct testimony?

A. Yes, it does.

Appendix A

PAUL R. CARPENTER **Principal**

Dr. Carpenter holds a Ph.D. in applied economics and an M.S. in management from the Massachusetts Institute of Technology, and a B.A. in economics from Stanford University. He specializes in the economics of the natural gas, oil and electric utility industries. Dr. Carpenter was a co-founder of Incentives Research, Inc. in 1983. Prior to that he was employed by the NASA/Caltech Jet Propulsion Laboratory and Putnam, Hayes & Bartlett, and he was a post-doctoral fellow at the MIT Center for Energy Policy Research. He is currently a Principal and Vice Chairman of *The Brattle Group*.

AREAS OF EXPERTISE

Dr. Carpenter's areas of expertise include the fields of energy economics, regulation, corporate planning, pricing policy, and antitrust. His recent engagements have involved:

- *Natural Gas and Electric Utility Industries*: consulting and testimony on nearly all of the economic and regulatory issues surrounding the transition of the natural gas and electric power industries from strict regulation to greater competition. These issues have included stranded investments and contracts, design and pricing of unbundled and ancillary services, evaluation of supply, demand and price forecasting models, the competitive effects of pipeline expansions and performance-based ratemaking. He has consulted on the regulatory and competitive structures of the gas and electric power industries in the U.S., Canada, the United Kingdom, continental Europe, Australia and New Zealand.

- *Antitrust*: expert testimony in several of the seminal cases involving the alleged denial of access to regulated facilities; analysis of relevant market and market power issues, business justification defenses, and damages.

- *Regulation*: studies and consultation on alternative ratemaking methodologies for oil and gas pipelines, on "bypass" of regulated facilities before the U.S. Congress; advice and testimony before several state utility commissions and the National Energy Board of Canada on new facility certification policy.

- *Finance*: research on business and financial risks in the regulated industries and testimony on risk, cost of capital, and asset valuation for network industries, airports and seaports in the U.S., Canada., Australia and New Zealand.

PROFESSIONAL AFFILIATIONS

International Association of Energy Economists
American Bar Association (Antitrust Section)
American Economic Association

ACADEMIC HONORS AND FELLOWSHIPS

Stewart Fellowship, 1983
MIT Fellowships, 1981, 1982, 1983
Brooks Master's Thesis Prize (Runner-up), MIT, 1978

PUBLICATIONS

"The Advent of U.S. Gas Demand Destruction and Its Likely Consequences for the Pricing of Future European Gas Supplies," (with Carlos Lapuerta and Morten Frisch), 16 March 2005.

"REx Incentives: Performance Based Ratemaking (PBR) Choices that Reflect Firms' Performance Expectations," (with Johannes P. Pfeifenberger and Paul C. Liu), *The Electricity Journal*, November 2001.

"Asset Valuation and the Pricing of Monopoly Infrastructure Services: A Discussion Paper," (with Carlos Lapuerta) 28 July 2000.

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"Methodologies for Establishing National and Cross-Border Systems of Pricing of Access to the Gas System in Europe," Report to the European Commission (with Carlos Lapuerta and Boaz Moselle), February 2000.

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"The Outlook for Imported Natural Gas," (with Matthew P. O'Loughlin and Gao-Wen Shao), prepared for The INGAA Foundation, Inc., July 1997.

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"Review of the Model Developer's Report, Natural Gas Transmission And Distribution Model (NGTDM) Of The National Energy Modeling System," December 1994, prepared for U.S. Department of Energy, Energy Information Administration and Oak Ridge National Laboratory under Subcontract No. 80X-SL220V.

"Pricing of Electricity Network Services to Preserve Network Security and Quality of Frequency Under Transmission Access," (with Frank C. Graves, Marija Ilic, and Asef Zobian) response to the Federal Energy Regulatory Commission's Request for Comments in its Notice of Technical Conference Docket No. RM93-19-000, November 1993.

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"Review of the Component Design Report, Natural Gas Annual Flow Module, National Energy Modeling System," August 1992, prepared for the U.S. Department of Energy, Energy Information Administration.

"Unbundling, Pricing, and Comparability of Service on Natural Gas Pipeline Networks," (with Frank C. Graves) November 1991, prepared for the Interstate Natural Gas Association of America.

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Joint Application of PECO Energy Company and Public Service Electric and Gas Company
Docket No. A-110550F0160

Errata to Direct Testimony of Paul R. Carpenter – PGW Statement No. 1

Location	Original	Corrected
p.4, line 19:	2.6 billion cubic feet	2.51 billion cubic feet
p.4, line 28	divestures	divestitures
p.5, line 4	The is no equivalent	There is no equivalent
p.5, line 28	PSEG ER&T,.	PSEG ER&T.
p.19, line 3	any other upstream	any other downstream
p.20, line 6	are committed upstream	are committed downstream
p.21, line 16	upstream of PJM East	downstream of PJM East
p.21, fn 42	upstream markets	downstream markets
p.22, line 7	2.6 Bcf/d	2.51 Bcf/d
p.24, fn 43	page 10	page 14

PGW EXHIBIT NO. 1

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TO PA PUBLIC UTILITY COMMISSION
JOINT APPLICATION OF PECO ENERGY COMPANY
A-110550F0160
FRIDAY, SEPTEMBER 23, 2005
PHILADELPHIA, PA
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STATEMENT 1, AND PGW STATEMENT 1-SR

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PGW Statement No. 1-SR PUBLIC
Docket No. A-110550F0160 Version
Witness: Paul R. Carpenter
9/23/05 Phila
DC

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

SURREBUTTAL TESTIMONY OF

PAUL R. CARPENTER

ON BEHALF OF
PHILADELPHIA GAS WORKS

Response to Rebuttal Testimony of Joint Applicants' Witnesses Hieronymus and Morris and Directed Questions 1 and 5

PUBLIC VERSION
CONFIDENTIAL MATERIAL REDACTED

Docket No. A-110550F0160

Joint Application of PECO Energy Company and Public Service Electric and Gas Company for Approval of the Merger of Public Service Enterprise Group Incorporated with and into Exelon Corporation

August 26, 2005

I. INTRODUCTION AND SUMMARY

Q. Dr. Carpenter, did you submit direct testimony in this proceeding?

A. Yes. I submitted direct testimony that showed that the proposed Exelon/PSEG merger raises significant vertical market power concerns. The merged entity would have market power in the PJM East natural gas market, and would have the incentive to use that market power to adversely affect competition in PJM East gas and electricity markets. I demonstrated that the vertical merger analysis submitted by Dr. William Hieronymus on behalf of the Applicants contained several errors, that when corrected established that the merged entity would have market power in the PJM East gas market. Most importantly, Dr. Hieronymus understated concentration in the PJM East gas market by including interstate transportation capacity that would not be available to serve PJM East in peak demand periods.

Q. What is the purpose of your surrebuttal testimony?

A. I have been asked by the Philadelphia Gas Works ("PGW") to respond to rebuttal testimony submitted by Dr. Hieronymus and Dr. John Morris on behalf of Exelon and PSEG. PGW has also asked me to respond to Directed Questions 1 and 5 of Vice-Chairman Cawley and Commissioner Shane in the July 15, 2005 Secretarial letter.[1] As part of my response to Question 5, I address the relevance of Mr. Arndt's

[1] Directed Question 1 asks, "Neighboring states have availed themselves of opportunities to enhance their economic competitiveness through access to economical energy resources. What opportunities exist from this proposed merger in terms of economic development for Pennsylvania? Specifically, does this proposed merger present us with an opportunity to strengthen the State's ability to remain competitive during periods of economic recession and volatile energy pricing?" Directed Question 5 asks, "Would the combination of the PSE&G gas division with the PECO gas division and the Philadelphia Gas Works provide critical mass for a viable, profitable, shareholder owned public utility, assuming a revenue stream from off system sales from an LNG facility, and separate resolution of the problem of a billion dollar debt?"

testimony that the divestiture of PECO and PSE&G's gas businesses would create additional costs.[2]

Q. Could you summarize your surrebuttal testimony?

A. Yes.

- I demonstrated in my direct testimony that there were errors in Dr. Hieronymus' vertical concentration analysis contained in his original testimony. In rebuttal, Dr. Hieronymus presents an entirely new gas market concentration analysis that corrects some of these errors but perpetuates the fundamental problem with his methodology – a geographic market that is too broad to correctly reflect competitive alternatives to the Applicant's natural gas capacity during peak periods in PJM East.

- Instead of performing his own analysis to justify this expanded geographic market, Dr. Hieronymus relies on the testimony of Dr. John Morris for his conclusion that "the value of gas flowing through PJM East and its value downstream rarely diverge by more than a trivial amount."[3] I demonstrate in this testimony that no such conclusion can be reached from Dr. Morris' work.

- Indeed, a more detailed and expanded analysis of prices than was performed by Dr. Morris indicates that there is nothing "trivial" about the frequency and magnitude of the price separation between the PJM East and New York/New England natural gas markets during peak demand periods. Thus, pipeline capacity serving the New York/New England region should be not be included in the same geographic market as the capacity serving PJM East for purposes of a gas market concentration analysis.

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[2] PECO Statement No. 2-R, Rebuttal Testimony of William D. Arndt, page 21.
[3] PECO Statement No. 3-R, Rebuttal Testimony of William H. Hieronymus, page 52.

- I also respond to Dr. Morris' claims that additional factors eliminate the ability of the merged entity to exercise market power in the PJM East gas market. These factors include: the use of interruptible transportation ("IT") capacity as a substitute for firm capacity, the fact that the utilities hedge their gas positions, that the merged entity could not create or benefit from increased price volatility, the entry of new LNG facilities on the East Coast, and pervasive regulatory oversight of PSEG ER&T by the New Jersey Board of Public Utilities ("New Jersey BPU"). I show that:

    - Dr. Morris' claim that IT is an economic substitute for firm transportation during peak periods is incorrect.

    - Whether the utilities hedge their gas position is irrelevant to whether they have the discretion to use their gas assets to create volatility and profit from that volatility. The evidence demonstrates that the merged entity will have substantial discretion in the use of its transportation and storage assets to move prices during peak periods while simultaneously serving their peak loads.

    - The potential entry of new LNG facilities on the East Coast is too speculative to rely on to mitigate the market power of the merged entity. Indeed, the more likely scenario is the construction of additional LNG capacity on the Gulf Coast, leading to further potential congestion on the pipelines serving PJM East.

    - The New Jersey BPU's regulatory authority over PSEG ER&T is not as all-pervasive as implied by Dr. Morris.

- Dr. Hieronymus did not respond in any way to the remedies I proposed in my direct testimony to address these vertical problems. Dr. Morris's response was simply to assert without support that my divestiture remedy "has no nexus to the alleged problem." He ignores completely my second, more targeted, remedy, but which would require greater regulatory oversight. Exelon witness Mr. Arndt suggests that I have ignored the potential costs of divestiture, but as I pointed out in my direct testimony, the Pennsylvania statutes require the Commission to remedy potential competitive harm before any merger can be approved.

Q. The Federal Energy Regulatory Commission ("FERC") approved the Exelon/PSEG merger after your direct testimony was filed in this proceeding. Does FERC's approval change your opinion about the likely effects of this merger?

A. No, and there is no evidence in the FERC decision that any of my testimony was considered. Indeed, Exelon itself stated in its Answer to the Requests for Rehearing that the testimony was filed too late to be considered, or was fully considered in FERC's response to Dr. George Briden's testimony on behalf of First Energy.[4] But, Dr. Briden's testimony was significantly different from mine.[5] Again, the fact that Exelon has chosen to introduce an entirely new witness on gas issues to attempt to buttress Dr. Hieronymus' original testimony – something they did not do in the FERC proceeding – is further evidence that the FERC's consideration of gas issues was superficial, at best.

[4] Answer of Exelon Corporation and Public Service Enterprise Group Incorporated to Requests for Rehearing, August 16, 2005, FERC Docket No. EC05-43, pages 20-22.

[5] Most importantly, Dr. Briden simply presented a vertical concentration analysis of the PJM East gas market intended to correct defects in Dr. Hieronymus' analysis. Dr. Briden did not provide testimony on PSEG Energy Resources and Trading's ("PSEG ER&T") current procurement activities on behalf of PSE&G. Nor did he provide any other testimony on the merged entity's ability and incentive to increase gas prices in PJM East other than his concentration analysis. Apart from these differences in our testimony, although Dr. Briden and I agree that downstream capacity should be excluded from the PJM East gas market, Dr. Briden's PJM East gas market concentration analysis was significantly different than mine. Dr. Briden adopted Dr. Hieronymus' methodology, and calculated a PJM East market size based on EIA data on pipeline capacity across state borders before allocating capacity into the market among firm contract holders. I used a different methodology, based only on contracts with firm delivery rights into PJM East. Dr. Briden did not make several of the corrections I made to contracts included by Dr. Hieronymus. For example, he included contracts that had receipt points solely within PJM East. It is apparent from the differences in our results that Dr. Briden and I performed different analyses. Dr. Briden calculated a post-merger HHI of 2,676 points, while my post-merger HHI was 1,942.

Q. How is the remainder of your surrebuttal testimony organized?

A. In Section II, I discuss the changes Dr. Hieronymus made in his rebuttal testimony to his analysis of concentration in the PJM East gas market. I explain why the PJM East gas market concentration analysis I submitted in my direct testimony is still the most appropriate, and why Dr. Hieronymus' new concentration analysis (like his prior analysis) assumes a market that is too broad. I also explain why PSEG's Transco capacity with firm delivery rights in PJM East should be considered in the PJM East gas market. In Section III, I address the factors that Dr. Morris contends prevent the merged entity from exercising market power in the PJM East gas market. I respond to Directed Questions 1 and 5, and I address Mr. Arndt's cost of gas divestiture and its relevance for the Commission's consideration of my suggested remedies in Sections IV and V.

II. THE PJM GAS MARKET IS HIGHLY CONCENTRATED DURING PEAK DEMAND PERIODS

Q. You raised a number of criticisms of Dr. Hieronymus' original PJM East gas market concentration analysis in your direct testimony. How did Dr. Hieronymus respond?

A. Dr. Hieronymus directed his staff to recheck all of the data he used in his initial market concentration study. As a result of this additional evaluation, Dr. Hieronymus accepted some of the corrections I made to his initial analysis:

(1) He added a number of contracts that he improperly excluded in his initial concentration analysis, apparently because he was treating them as if they expire in 2005 when in fact they do not. In particular, Dr. Hieronymus now includes three contracts held by PECO and PSEG with capacity of approximately 117 MMcf/d that have delivery rights in PJM East that he had initially treated as if they expired.

(2) He added a number of contracts that he had improperly excluded in his initial concentration analysis, apparently because he was treating them as if they did not

have delivery rights in the PJM East market when in fact they do have firm delivery rights in PJM East.

(3) He excluded several contracts that he had included in his initial concentration analysis even though they have receipt rights that were solely within the PJM East gas market and thus could not be used to counter withholding into PJM East. In particular, he excluded a contract held by PECO and a contract held by PSEG totaling approximately 187 MMcf/d that have receipt rights solely within PJM East.[6]

Q. Are these the only changes Dr. Hieronymus made to his PJM East gas market concentration analysis?

A. No. Dr. Hieronymus made two additional changes: (1) he increased his measure of the total size of the PJM East gas market, and (2) he changed his methodology for allocating pipeline capacity to capacity holders.

In both his initial and rebuttal concentration analysis, Dr. Hieronymus used data from the EIA on pipeline capacity across state borders to determine his PJM East market size. Initially, he did not include capacity on Transco's Leidy Line, a bi-directional line that transports gas between the Leidy hub/storage fields in western Pennsylvania and PJM East, in his calculation of the size of the PJM East market. Now, he has added 885 MMcf/d to his PJM East market size, representing capacity on Transco's Leidy Line.[7] Increasing the size of the PJM East market in this way decreases Dr. Hieronymus' measure of market concentration.

Dr. Hieronymus also changed his methodology for allocating pipeline capacity to capacity holders. In his initial concentration analysis, Dr. Hieronymus used interstate

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[6] In his rebuttal analysis, Dr. Hieronymus excluded a Texas Eastern contract held by PECO's contract with capacity 117 MMcf/d and receipt rights in PJM East at Eagle Station, but did not exclude a Texas Eastern contract held by Sun Refining with receipt rights in PJM East at Eagle Station. However, the Sun Refining contract is small (6 MMcf/d) and excluding it would not have a material effect on Dr. Hieronymus' rebuttal results.

[7] PECO Statement No. 3-R, Rebuttal Testimony of William H. Hieronymus, page 58, lines 11 to 15. Dr. Hieronymus' measure of the size of the PJM East market increased by 897 MMcf/d in total, mainly due to his addition of Transco's Leidy Line, but also because he is now using more recent EIA pipeline capacity data.

pipeline Index of Customers reports to identify holders of firm transportation capacity into PJM East. He treated these capacity holders as having capacity in the PJM East market equal to their pipeline capacity with firm delivery rights into PJM East. Texas Eastern and other pipelines that serve PJM East deliver significant volumes into the Algonquin pipeline in New Jersey, for eventual delivery by Algonquin downstream in New England. However, Dr. Hieronymus treated firm delivery rights into Algonquin in the same way he treated all other firm delivery rights in PJM East, *i.e.*, as if delivery rights into Algonquin for ultimate delivery downstream were the same as delivery rights in PJM East.

In his initial analysis, two pipelines (Transco and Tennessee) had capacity into PJM East that was greater than total firm delivery rights within PJM East. Therefore, Dr. Hieronymus assigned capacity equal to the difference between his measure of the pipelines' size and their total firm delivery rights in PJM East to the pipeline owners.[8] Thus, El Paso (owner of Tennessee) and Williams Energy (owner of Transco) were the third and fourth largest market participants in Dr. Hieronymus' initial market concentration study.[9] Dr. Hieronymus characterized this allocation of capacity to pipeline owners as an assignment of "unsubscribed capacity" to pipeline owners.[10] In reality, this capacity was not unsubscribed. As I pointed out in my direct testimony,[11] it was subscribed by firm shippers to markets downstream of PJM East.

In his revised analysis, instead of identifying holders of firm transportation capacity into only PJM East, Dr. Hieronymus identifies holders of firm transportation into PJM East <u>and</u> markets downstream of PJM East, namely eastern New York. Under his new methodology, Dr. Hieronymus explicitly recognizes entities that hold capacity downstream of PJM East as PJM East market participants.[12] As a result, he

8 The remaining two pipelines (Columbia and Tennessee) had capacity that was smaller than total firm delivery rights in PJM East. So, Dr. Hieronymus prorated the capacity allocated to small market participants so that his allocated capacity matched his market size.

9 Some of the capacity allocated to Williams (116 MMcf/d out of 318 MMcf/d) represents capacity held by Williams on Texas Eastern, and not Transco capacity allocated to Williams, Transco's owner.

10 Exhibit WHH-1 (Revised) page 72, line 21 to 73, line 1 and Exhibit J-4, page 14.

11 At page 21, lines 15-16.

12 Previously, the only entities that holding downstream capacity that he explicitly recognized were those who held capacity on Texas Eastern that delivered into Algonquin.

does not allocate significant capacity to pipeline owners despite the fact that his total market size is much larger than in his original analysis.[13] Exelon/PSEG is still the largest capacity holder in PJM East in Dr. Hieronymus' revised analysis. However, KeySpan and Consolidated Edison, which were not significant capacity holders in his initial analysis, are the second and third largest PJM East market participants in Dr. Hieronymus' revised analysis.[14] Almost all of Keyspan and Consolidated Edison's capacity has delivery rights downstream of PJM East in New England or eastern New York, or into Algonquin for ultimate delivery downstream of PJM East.[15]

Q. Overall, how has Dr. Hieronymus' measure of concentration in the PJM East changed?

A. Table 1 below shows the changes in the size of the PJM East market, the merged entity's capacity, and the HHI:

Table 1
Dr. Hieronymus' Measures of Concentration in the PJM East Gas Market

	Dr. Hieronymus' Direct Testimony	Dr. Hieronymus' Rebuttal Testimony
Exelon / PSEG Capacity	2,115 MMcf/d	1,974 MMcf/d
Total Market Size	5,934 MMcf/d	6,831 MMcf/d
HHI	1,572	1,292

Source: Exhibit J-16 from Exhibit WHH-1.
Table 8 from PECO Statement No. 3-R- Rebuttal Testimony of William H. Hieronymus.

13 Total firm delivery rights into PJM East and downstream markets are still smaller than capacity for Tennessee in Dr. Hieronymus' revised analysis, so he allocates a small amount (84 MMcf/d compared to 322 MMcf/d in his initial analysis) of capacity to Tennessee's owner El Paso.

14 Dr. Hieronymus did not show KeySpan or Consolidated Edison as holding more than 100 MMcf/d in his initial concentration analysis. Now, he shows KeySpan with capacity of 1,002 MMcf/d, and Consolidated Edison with capacity of 659 MMcf/d.

15 KeySpan holds at most 55 MMcf/d of capacity with firm delivery rights in PJM East. Consolidated Edison holds only 19 MMcf/d with firm delivery rights in PJM East.

The changes Dr. Hieronymus has made to his total market size are responsible for most of the reduction in his HHI from his original testimony.

Q. Does Dr. Hieronymus' decision to include Transco's Leidy Line in his measure of PJM East market size, and to allocate capacity differently, cause you to make changes in your PJM East gas market concentration analysis?

A. No. I do not agree with Dr. Hieronymus' original or revised methodologies. They both are erroneous in that they overstate the size of the relevant geographic market and the amount of pipeline capacity that is available to serve that market during peak periods. By overstating the size of the relevant geographic market and the amount of pipeline capacity available, his analysis improperly supports the merger. Because my methodology is different from his, the changes he made in his rebuttal testimony have no relevance for my concentration analysis.

Q. What is the essential difference between Dr. Hieronymus' revised measure of concentration in the PJM East gas market and the measure you submitted in your direct testimony?

A. The essential difference is that Dr. Hieronymus includes interstate capacity with delivery rights downstream of PJM East, in New England and New York, in the PJM East gas market. I exclude capacity that has delivery rights downstream of PJM East since this capacity will not be available to deliver to PJM East in time periods when those two markets are distinctly separate due to pipeline capacity constraints between them.

This was also the most important difference between Dr. Hieronymus' initial concentration analysis and the analysis in my direct testimony. However, in his rebuttal testimony Dr. Hieronymus does no additional work to justify this broader geographic market, and instead relies on testimony submitted by Dr. Morris to support his argument that delivery rights in New England and New York should be included in the PJM East gas market.

Q. Does Dr. Morris claim that New England and New York are in the same geographic market as PJM East?

A. Yes, he does but with flawed assumptions. He reaches this conclusion by comparing the price of natural gas delivered in PJM East to the prices of natural gas delivered in New York and New England. Dr. Morris claims that because the New York and New England prices were less than 5 percent greater than the PJM East price for 90 percent of the days during July 2003 to July 2005, that pipeline capacity delivering to New York and New England is in the same geographic market as pipeline capacity delivering to PJM East.[16] Dr. Morris claims that the Department of Justice/FTC *Horizontal Merger Guidelines*[17] require the use of this "5 percent test" to define relevant geographic markets.

Q. Do the Department of Justice/FTC *Horizontal Merger Guidelines* support the price difference test that Dr. Morris relies upon for his conclusion that pipeline capacity to New England and New York are in the same geographic market as pipeline capacity delivering into PJM East?

A. No. Dr. Morris distorts the market definition framework outlined in the *Horizontal Merger Guidelines*. The *Horizontal Merger Guidelines* state with respect to market definition:

> A market is defined as a product or group of products and a geographic area in which it is produced or sold such that a hypothetical profit-maximizing firm, not subject to price regulation, that was the only present and future producer or seller of those products in that area likely would impose at least a "small but significant and nontransitory" increase in price, assuming the terms of sale of all other products are held constant. A relevant market is a group of products and a geographic area that is no bigger than necessary to satisfy this test.

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16 PECO Statement No. 11-R, Rebuttal Testimony of John R. Morris, pages 17 to 20.

17 U.S. Department of Justice/Federal Trade Commission, *Horizontal Merger Guidelines*, 57 Fed. Reg. 41,552 (1992), *revised* 4 Trade Reg. Rep. ¶ 13,104, (April 7, 1997).

> The "small but significant and non-transitory" increase in price is employed solely as a methodological tool for the analysis of mergers: it is not a tolerance level for price increases.[18]

The *Horizontal Merger Guidelines* also state that "Market definition focuses solely on demand substitution factors – i.e., possible consumer responses."[19] Therefore, under the *Horizontal Merger Guidelines*, the product market is dependent upon the demand conditions prevailing at the time a hypothetical increase in price is considered to be imposed by a monopolist. Seasonal fluctuations in demand, such as seen in natural gas markets in the Northeast United States, where demand peaks in the winter heating season, should be considered in defining the relevant market, a factor that Dr. Morris does not consider. In addition, the *Horizontal Merger Guidelines* does not contemplate the simplistic price comparison test utilized by Dr. Morris.

Q. Does the FTC support defining multiple product markets for merger analysis that depend upon demand levels?

A. Yes. The FTC's experience with electricity mergers has led it to conclude that there are multiple, different product markets for electricity depending upon the prevailing demand level. The FTC Staff states:

> Given that the product market is defined in terms of the demand conditions under which a hypothetical monopolist could profitably raise price by a small non-transitory amount and that electricity cannot be readily stored for subsequent consumption, any individual electrical industry merger is likely to involve a number of separate product markets that are based in large part upon reliability or accessibility. Demand characteristics for electricity and transmission services are likely to differ, for example, at different times of the day, different seasons of the year, different points in the business cycle, with different levels of risk of service interruption, and for different lengths of contract.[20]

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18 U.S. Department of Justice/Federal Trade Commission, *Horizontal Merger Guidelines*, 57 Fed. Reg. 41,552 (1992), *revised* 4 Trade Reg. Rep. ¶ 13,104, (April 7, 1997), § 1.0.

19 U.S. Department of Justice/Federal Trade Commission, *Horizontal Merger Guidelines*, 57 Fed. Reg. 41,552 (1992), *revised* 4 Trade Reg. Rep. ¶ 13,104, (April 7, 1997), § 1.0.

20 Comment of the Staff of the Bureau of Economics of the Federal Trade Commission, FERC Docket No. RM96-6-000, May 7, 1996, § 2 (footnote omitted).

Even though natural gas is more readily storable than electricity, the demand characteristics for natural gas also differ by day and season. The FTC Staff continues with comments on how to define the relevant geographic market when there are temporal changes in demand conditions that cause multiple relevant product markets:

> Perhaps the most critical element in an analysis of electricity mergers is the extent of the relevant geographic market. Defining the geographic market may be difficult because it may involve many factors and factor interactions. The hypothetical monopolist in a particular hypothesized geographic market may face very different degrees of constraint from more distant alternative supply sources at different times of the day, different times of the year, different points in the business cycle, etc., leading to the conclusion that the geographic market differs for different product markets related to the same acquisition. Differences in the degree and sources of geographic competition may arise because the temporal distinctions between product markets may well be associated with variations in transmission conditions, generating conditions, and existing transmission and generating obligations. For example, supply from generator X that is currently contractually obligated to supply local load is unlikely to be part of the market for short-term capacity to serve distant area Y. However, supply from generator X might well be in the market for intermediate-term capacity to serve area Y, if the local contract of generator X expires before the intermediate term.[21]

These statements by FTC Staff support the concept that a merger analysis should look at the demand conditions in determining the relevant product and geographic markets. Dr. Morris' simple price comparison analysis is flawed because it does not consider seasonal changes in demand. As I show below, the very large separations in prices between the two regions that are observed during the peak demand winter months support the conclusion that pipeline capacity serving New York and New England are in a separate market from pipeline capacity serving PJM East.

Q. What are the seasonal variations in demand for natural gas in the northeast United States?

A. Demand for natural gas peaks during the winter months in the northeast United States because of heating requirements. This peak in demand is illustrated in Figure 1 of Dr.

[21] *Id.*

Hieronymus' Rebuttal Testimony that shows demand by local distribution companies in the New York and New England areas increasing by 300% in the winter months compared to summer months, from less than 2 Bcf/d in the summer months to approximately 6 Bcf/d or more in the winter months.[22] This increase in demand causes flows on the interstate pipelines to increase dramatically and often causes constraints on the pipeline system to occur between locations. When constraints occur, prices between locations separate because arbitrage between locations is not possible. For example, when the price of gas in New York or New England becomes 20 to 25 percent greater than the price of gas in PJM East, as shown in Figure 3 of Dr. Morris' Rebuttal Testimony,[23] all pipeline capacity that is not serving load in PJM East and is capable of flowing through PJM East with primary delivery points in New York or New England will be used to serve the New York or New England markets with the higher prices.[24] Further, because the prices do separate between regions during the peak demand winter months, this is evidence that there are constraints that limit the ability of natural gas to move between regions, and all capacity that can move between the two regions is being fully utilized.[25] This price separation is thus also evidence that pipeline capacity delivering to New York and New England is not in the same geographic market as pipeline capacity delivering to PJM East during the peak demand winter months.

Q. What is the magnitude of the separation of natural gas prices between New York or New England and PJM East during the peak winter months?

A. During the two winters considered by Dr. Morris (November 2003 to March 2004 and November 2004 to March 2005), the average daily price in New York exceeded the

[22] PECO Statement No. 3-R, Rebuttal Testimony of William H. Hieronymus, pages 49-50, Figure 1.

[23] PECO Statement No. 11-R, Rebuttal Testimony of John R. Morris, page 20, Figure 3.

[24] Pipeline capacity with primary delivery points in both PJM East and New York could be considered to be in both markets if there is evidence that deliveries are made into both areas when prices separate during peak periods.

[25] Withholding of pipeline capacity through an exercise of market power is another possible reason for prices between regions to separate.

average daily price in PJM East by $0.75/MMBtu. The average daily price in New England exceeded the average daily price in PJM East by $0.63/MMBtu.[26]

Table 2 presents average daily prices in winter months for the previous four winters, a longer time period than the period considered by Dr. Morris, for New York, New England, PJM East, and the Henry Hub:

Table 2
Average Daily Gas Prices in Winter Months

	Average Daily Gas Price ($/MMBtu)				Difference btw Avg Price	Difference btw Avg Price
	New York	New England	PJM East	Henry Hub	in New York and PJM East	in New England and PJM East
During 11/1/01 - 3/31/02	$ 2.94	$ 2.92	$ 2.84	$ 2.47	$ 0.10	$ 0.08
During 11/1/02 - 3/31/03	$ 7.34	$ 7.50	$ 7.14	$ 5.49	$ 0.20	$ 0.36
During 11/1/03 - 3/31/04	$ 7.10	$ 7.30	$ 6.53	$ 5.49	$ 0.56	$ 0.77
During 11/1/04 - 3/31/05	$ 8.31	$ 7.84	$ 7.36	$ 6.35	$ 0.95	$ 0.48

Source: *Gas Daily*. New York daily price is Transco New York price. New England daily price is Algonquin Citygates price. PJM East daily price is Transco non-New York price.

During the period considered by Dr. Morris, almost all of the days that fail his 5% test are in the winter. During 2003 to 2005, the New York price exceeds 105% of the PJM East price on 23% of winter days, and the New England price exceeds the PJM East price on 24% of winter days. On days when the New York and New England prices exceed the PJM East price, they exceed the PJM East price by a significant amount in absolute terms. During the 23% of winter days during 2003 – 2005 when the New York price exceeds 105% of the PJM East price, the New York price exceeds the PJM East price by $3.00/MMBtu on average. During the 24% of winter days during 2003 – 2005 when the New England price exceeds 105% of the PJM East price, the New England price exceeds the PJM East price by $2.20/MMBtu on average.

Prior to the 2003 – 2005 period considered by Dr. Morris, his 5% test also fails for the New York and PJM East markets during some summer periods, particularly in the summer of 2002.[27]

[26] The average daily price in New York was $7.68/MMBtu, the average daily price in New England was $7.56/MMBtu, and the average daily price in PJM East was $6.93/MMBtu.

Contrary to Dr. Hieronymus' statement on page 52 of his rebuttal testimony, the level and duration of these price differences is hardly "trivial."

Q. If natural gas prices in New York and New England are much higher than prices in PJM East during peak demand periods, is it reasonable to assume that the pipeline capacity serving New York and New England would be diverted to PJM East as Dr. Morris claims?

A. No. Because peak period prices are higher in New York and New England than in PJM East, pipeline capacity that is capable of reaching New York and New England will be used to serve those higher priced markets, and not the lower priced PJM East market. It is precisely for this reason that pipeline capacity capable of serving New York and New England should be considered to be in a separate geographic market than the capacity contracted to PJM East destinations during peak demand periods.

Q. Does Dr. Morris' use of a strict 5 percent price difference influence his results given that gas prices in PJM East vary greatly day-to-day?

A. Yes. As shown in Figure 2 of Dr. Morris' Rebuttal Testimony,[28] daily natural gas prices in PJM East are very volatile during the period he considers. Daily gas prices in PJM East during November 2003 to March 2004 varied between \$4.17/MMBtu and \$29.64/MMBtu. Thus, 5% of the PJM East price varied between \$0.21/MMBtu and \$1.49/MMBtu. Since daily prices are volatile and Dr. Morris uses a test based on a percentage threshold, his test passes on a number of days where the price difference between PJM East and New York is still quite high in absolute terms. During November 2003 to March 2004, Dr. Morris' five percent test passes on three days when the New York price exceeds the PJM East price by more than \$0.30/MMBtu,

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[27] Dr. Morris' 5% test fails for the New York and PJM East markets on 9 days during the summer of 2001 (June 27-July 2 and August 8-10) and 31 days during the summer of 2002 (June 26-27, July 2-9, July 17-19, July 23, July 30-August 5, and August 10-August 19).

[28] PECO Statement No. 11-R, Rebuttal Testimony of John R. Morris, page 19, Figure 2.

and on eleven days when the New York price exceeds the PJM East price by more than $0.20/MMBtu.[29]

Q. Dr. Hieronymus argues that if capacity with delivery rights in New England and New York is excluded from the PJM East market, then almost all of PSEG's Transco capacity must also be excluded. Do you agree?

A. No, I do not. Dr. Hieronymus states that most (794 MMcf/d out of 840 MMcf/d) of PSEG's Transco capacity with firm delivery rights in PJM East in New Jersey is also deliverable on a firm basis to the New York citygates, so it can command New York prices. What this ignores is that this portion of PSEG's Transco capacity represents almost half (794 MMcf/d out of 1,663 MMcf/d, or 48%) of PSEG's total interstate capacity into PJM East. A significant portion of PSEG's Transco capacity is needed to meet PSE&G's BGSS requirements in PJM East during winter months.[30] Thus, a significant portion cannot be sold into the spot market downstream of PJM East at New York prices. The portion of PSEG's Transco capacity that is needed to meet PSE&G's BGSS load should be included in PJM East, just as capacity held by other suppliers that is used to meet local distribution company load obligations in PJM East has been included in the PJM East market by me and by Dr. Hieronymus.

Q. What is the magnitude of PSEG's sales in New York using its Transco capacity when New York gas prices exceed PJM East gas prices by more than 5%?

A. [redacted]

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[29] Similarly, during November 2004 to March 2005, Dr. Morris' five percent test passes on twelve days when the New York price exceeds the PJM East price by more than $0.20/MMBtu.

[30] Dr. Morris states, "When PJM East prices separate from New York and New England is when the vast majority of gas sold by EEG and other sellers would be at prices set by regulated rates..." Thus, Dr. Morris is asserting that when PJM East prices separate from New York and New England prices, most of PSEG's sales are meeting PSE&G's BGSS load located in PJM East. PECO Statement No. 11-R, Rebuttal Testimony of John R. Morris, page 25, lines 9-12.

[redacted]

Q. Dr. Hieronymus suggests that removing PSEG's Transco capacity from the PJM East market (and considering it to be part of the New York market) when New York gas prices are significantly higher than PJM East gas prices indicates that the merged entity does not have market power in his geographic PJM East gas market. Do you agree?

A. No, I do not. [redacted]

[redacted]

[redacted]

[31] Calculated from PSEG Response to Data Request PGW IV-9. [redacted]

[32] [redacted]

[33] [redacted]

[redacted]

Q. Dr. Morris also submitted a measure of gas market concentration. What relevance does his concentration measure have for your vertical analysis?

A. Dr. Morris submitted yet another measure of market concentration in the PJM East gas market that differs from both Dr. Hieronymus' original and rebuttal testimony results. It should be ignored by the Commission for the same reason that Dr. Hieronymus' original and revised market concentration analyses should be ignored: Dr. Morris' analysis includes downstream capacity that will not be available in PJM East during peak demand periods.

In fact, Dr. Morris includes significantly more downstream (New York and New England) capacity in his PJM East market concentration analysis than does Dr. Hieronymus, thus compounding the prior error. Dr. Morris includes capacity on three pipelines, Maritimes & Northeast, Portland Natural Gas Transmission, and Iroquois Gas Transmission, which do not physically serve PJM East. These pipelines physically serve only the New York and New England markets and thus are inappropriately included in the relevant market. Even Dr. Hieronymus does not include capacity on these pipelines in his PJM East market concentration analysis.

Q. Dr. Morris argues that a significant portion of the capacity with firm delivery rights in New England that traverses PJM East could be used for deliveries in PJM East during winter. Is this opinion consistent with recent studies of the New England gas market?

A. No. FERC and the ISO New England have recently studied the New England gas market. The FERC, in consultation with the Department of Energy, prepared a report on the natural gas pipeline system in New England in December 2003.[34] FERC found that the New England gas pipeline system is fully loaded during winter months, and thus capacity to New England is not available to the PJM East market. The FERC report states:

> Natural gas infrastructure expansion [in New England] has kept up with demand, yet with little margin for error. Any delay in the construction of planned infrastructure or underestimates of demand during December through February could result in insufficient capacity to meet demands. During these peak demand months, interstate pipelines in New England are fully loaded.[35]
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> *******
>
> The New England gas pipeline system is fully loaded December through February, and projected increases in capacity are expected to be completed just-in-time to meet new capacity demands. There is little opportunity for this system to rely on excess capacity as a buffer against curtailment. Should the unexpected occur, a localized curtailment of service is the likely outcome.
>
> Development of additional natural gas supply or construction of new LNG terminals in the New England region will require additional pipeline capacity. This is not anticipated until 2007-2010.[36]

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[34] "New England Natural Gas Infrastructure," Staff Report of the Federal Energy Regulatory Commission, FERC Docket No. PL04-01-000, December 2003.

[35] *Id.*, page 3.

[36] *Id.*, page 23.

FERC made several recommendations to maintain reliable gas service in New England "[i]n recognition of the high winter loading rates of the existing pipeline infrastructure and the just-in-time approach to meet additional capacity demands".[37]

The ISO New England commissioned several studies of the New England gas market over the last few years. A recent study by Merrimack Energy Group on behalf of the ISO New England found that the New England gas market will remain tight during peak winter periods over the next several years. Merrimack also found that incremental East Coast LNG supply is needed in New England, making it unlikely that these supplies will be available in PJM East in peak winter demand periods. Merrimack stated:

> Due to competition for gas supply with neighboring markets and the limited prospects for new, incremental gas supplies in the next few years, it is likely that upward price pressure and supply competition will continue to be a problem during peak winter periods in New England. Based on the demand and supply trends identified in this report, new supply sources will be required by the 2007-2008 timeframe. Of the incremental supply options for the near term (i.e., 2007-2010) is LNG. Since other supply options are not likely to be available during that timeframe, New England's gas supply requirements in the near term will have to be met by new LNG facilities.
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> ********
>
> [I]t appears that at least one (or two) LNG projects, with access to the New England market, will be required to meet the gas supply requirements of the New England market. Without these projects, prices will continue to be volatile during the peak winter months and competition for gas supply will heighten between the traditional LDC gas markets and the power generators.[38]

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37 *Id.*, page i.

38 "New England Natural Gas Supply Assessment," Developed for ISO New England Inc. by Merrimack Energy Group, April 1, 2005, pages 2-3. Merrimack discusses how competition from neighboring markets will affect the New England gas market in Section V of the report. However, they do not see PJM East as competing with New England for gas supplies. Merrimack lists Ontario, Quebec, Eastern Canada, and New York as neighboring markets that compete with New England for gas supplies.

Q. What do you conclude about the merger's effect on concentration in the natural gas market serving PJM East?

A. The analysis of concentration in the PJM East natural gas market contained in my direct testimony provides the best evidence before the Commission as to the effect of the merger on concentration in the upsteam gas market during peak demand periods. The new measures of concentration provided by Drs. Hieronymus and Morris and the pricing analysis provided by Dr. Morris and relied on by Dr. Hieronymus do not provide an economic basis for employing an expanded geographic market in this case.

III. DR. MORRIS HAS NOT SHOWN THAT THE APPLICANTS LACK THE ABILITY TO EXERCISE MARKET POWER

Q. What additional factors does Dr. Morris claim eliminate the ability of the merged entity to exercise market power in the PJM East Gas Market?

A. Dr. Morris claims that the following factors eliminate the merged entity's ability to exercise market power: (1) use of interruptible transportation as a substitute for firm capacity; (2) the fact that the utilities hedge their gas positions; (3) that the merged entity could not create or benefit from increased price volatility; (4) the entry of new East Coast LNG facilities; and (5) pervasive regulatory oversight of PSEG ER&T by the New Jersey BPU.

Q. Does Dr. Morris claim that interruptible transportation is an economically viable substitute for firm transportation to PJM East?

A. Yes. Dr. Morris claims that interruptible transportation is an economically viable substitute for firm capacity, even during peak demand periods.[39] Dr. Morris claims that interruptible transportation becomes attractive when the price of natural gas

[39] PECO Statement No. 11-R, Rebuttal Testimony of John R. Morris, page 21.

delivered in PJM East exceeds the price in the producing basin by more than the maximum tariff rates on the interstate pipelines transporting to PJM East.

Q. Is interruptible transportation a substitute for firm transportation?

A. Interruptible transportation is a poor substitute for firm transportation because it is inherently unreliable, particularly in times of peak demand. Interruptible transportation is the first type of scheduled volumes to be curtailed due to operational constraints on a pipeline that occur for a number of reasons. Interruptible transportation is also subject to being curtailed ("bumped") by firm transportation rights.

Q. Dr. Morris claims that PECO and other LDCs in PJM East offer back-up natural gas sales services that allow generators in their service territories to rely on interruptible transportation even in peak demand periods.[40] Do back-up sales services make interruptible transportation a substitute for firm transportation?

A. No. I have reviewed the documents that Dr. Morris relied on regarding back-up sales service in PJM East.[41] First, it is important to note that PSE&G does not offer a firm back-up sales service.[42] PECO and several other LDCs in PJM East offer firm back-up sales services. However, a generator would incur significant costs for subscribing to these services. Therefore, the fact that PECO and other LDCs in PJM East offer these services does not imply that interruptible capacity is a good substitute for firm capacity in PJM East.

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40 *Id.*, page 35.

41 PECO Energy Response to Data Request PGW VI-4.

42 PSE&G has an Emergency Sales Service, but this service is not firm. It is offered at PSE&G's sole discretion. PSE&G also offers an interruptible transportation service under its Rate Schedule TSG-NF to customers who have backup fuel suppliers or are otherwise able interrupt their gas usage. This service is also not firm. And, charges are quite high for Rate Schedule TSG-NF customers who do not discontinue gas usage after they have been curtailed. Customers who do not discontinue gas usage when they have been curtailed pay ten times the highest daily price published in *Gas Daily* at either Transco Zone 6, New York or Texas Eastern Zone M-3 for the gas they consume.

For example, electric generators taking service under PECO's Standby Sales Service must enter into a contract with a duration of at least one year, and must specify a Standby Service Quantity ("SSQ") which is the maximum daily amount of gas the generator can purchase from PECO.[43] During summer months of its contract, regardless of the amount of gas the generator purchases from PECO, the generator must pay a minimum monthly distribution charge equal to $18.00/Mcf times its SSQ.[44] In winter months, if the generator purchases its SSQ from PECO on one day, it must pay a minimum monthly demand charge of $22.52/Mcf times its SSQ. If it uses PECO's standby service on a 100% load factor basis (it purchases its SSQ from PECO every day), it pays distribution charges equivalent to $0.98/Mcf (plus PECO's WACOG) for the volumes it purchases from PECO.[45] If the generator purchases from PECO on only 10 days during the month, it pays a distribution charge equivalent to $2.25/Mcf (plus PECO's WACOG) for the volumes it purchases from PECO.[46] In effect, the generator must reserve capacity on the PECO system, and pay a monthly demand charge for this reservation.[47]

Q. **Is interruptible transportation used by shippers instead of purchasing delivered gas in a destination area such as PJM East whenever there is slack capacity on a pipeline?**

A. No. Because interruptible transportation is subject to being curtailed by firm transportation rights or for operational reasons, consumers that value reliability of

[43] The generator must pay a penalty of $25/Mcf for any volumes purchased from PECO in excess of its daily SSQ.

[44] This is $1.5013 times the volume that would result from 15 days' use of 80% of the generator's SSQ. See PECO Energy Company Gas Service Tariff, Eighth Revised Page No. 45, Original Page No. 55 and First Revised Page No. 56.

[45] The generator pays a variable demand charge equal to $1.5013/Mcf for its first 15 days of purchases from PECO, and $0.4622/Mcf for its purchases during the remainder of the month. Thus, it pays $0.98 (=(1.5013+0.4622)/2) for all volumes purchased. See PECO Energy Company Gas Service Tariff, Eighth Revised Page No. 45.

[46] The generator pays the minimum distribution charge of $22.52/Mcf times its SSQ, and purchases 10 times its SSQ. Thus, it pays $2.25/Mcf for the volumes purchased from PECO.

[47] Three other back-up supply services relied on by Dr. Morris (for Delmarva Power & Light Company, Elizabethtown Gas Company, and Philadelphia Gas Works) also require a contract of at least a year and payment of demand charges on a specified daily maximum quantity that can be purchased under back-up supply service.

supply will choose to purchase delivered gas in the destination area, instead of purchasing gas in the producing basin and attempting to transport the gas via interruptible transportation to the destination area. This is because there is a risk that the interruptible transportation will be curtailed and the consumer will not be able to move the gas it purchased in the producing basin. Purchasing delivered gas in the destination area alleviates the risk associated with interruptible transportation being curtailed.

Q. Is there evidence regarding the use of interruptible transportation to counteract pipeline capacity withholding when there is some slack capacity on interstate pipelines?

A. While data with respect to the interstate pipelines flowing into PJM East is not available in this proceeding, substantial data on the use of interruptible capacity on the El Paso Natural Gas Pipeline ("EPNG") was made available in a prior proceeding before the FERC.[48] Evidence presented in that case demonstrated that interruptible transportation did not counteract capacity withholding. Conditions in PJM East are not so different that one would likely draw a different conclusion.

EPNG's marketing affiliate El Paso Merchant Energy ("EPME") held a large block of capacity on EPNG during 2000-2001. During the summer of 2000, there was slack capacity on EPNG and the evidence showed that EPME withheld a portion of its firm EPNG capacity from the market. While some interruptible transportation flowed on EPNG, EPME was able to sell significant volumes of gas at prices that <u>exceeded</u> the cost of using interruptible transportation.[49] In that well-documented case, interruptible transportation was not an economic alternative for customers purchasing gas from EPME and thus it did not undercut the capacity withholding by EPME.

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[48] FERC Docket No. RP00-241.

[49] Exhibits SCE-143 to SCE-145 in FERC Docket RP00-241. Also Figures III-17, 18 and 19 from Exhibit SCE-4, and Exhibit EPNG-24.

Q. Does Dr. Morris claim that the merged PSEG/Exelon entity could not increase the volatility of natural gas prices in PJM East area?

A. Yes. Dr. Morris claims that the merged entity could not increase or decrease price (which would increase volatility), and in addition, that the merged entity would not benefit from an increase in volatility.[50] Dr. Morris further claims that the merged entity would not have the operational flexibility to select how much demand is met by flowing interstate supply versus storage withdrawal.[51] But Dr. Morris offers no evidence on the merging entities' existing operational flexibility to support his claims. Because an unregulated entity, PSEG ER&T, controls the transportation and storage assets of PSE&G's regulated gas distribution utility operations, it appears that the unregulated affiliate has considerable discretion on whether the regulated gas distribution demand is met by flowing interstate supply, versus storage withdrawal, as well as considerable discretion in its volume of sales to third parties.

Q. What evidence is there that the merged entity would have discretion over the volume of storage injections and withdrawals?

A. Contrary to Dr. Morris' unsupported assertion that PSEG and PECO do not have operational flexibility with respect to storage activity,[52] both entities have substantial existing storage contracts that provide flexibility on the timing of withdrawals from and injections into storage.

PSEG has a maximum withdrawal capability (excluding its peaking facilities) of over 0.9 Bcf/d from storage facilities with approximately 80 Bcf of inventory capacity.[53] Therefore, at maximum withdrawal rates, PSEG can withdraw its 80 Bcf of inventory in approximately 85 days during the 151 day winter period (November 1st – March 31st). While there are some restrictions on the withdrawal and injection rates that

[50] PECO Statement No. 11-R, Rebuttal Testimony of John R. Morris, pages 29-34 and 40-43.
[51] *Id.*, page 39.
[52] *Id.*, page 39.
[53] PECO Energy response to Data Request PGW VI-9.

vary by inventory level and season,[54] these restrictions still grant PSEG a great deal of daily flexibility as to whether it withdraws gas from storage or uses its interstate pipeline transportation capacity contracts to meet its needs.[55]

PECO's storage contracts provide a maximum firm storage withdrawal capability (excluding its peaking facilities) of approximately 250 MMcf/d and over 19 Bcf of inventory capacity.[56] PECO's storage inventory can be withdrawn in approximately 75 days during the 151 day winter season. Again, like PSEG, there are some restrictions on withdrawal and injection rates that depend on storage inventory level. However, these restrictions permit significant day-to-day flexibility as to whether demand is met by flowing supply on the interstate pipelines or by storage withdrawal.

Q. **If the merged entity has the ability to increase prices, does it also have the ability to decrease prices?**

A. Yes. If the merged entity can increase the price above the competitive level by withholding capacity during peak demand periods, then it also has the ability to lower prices from this increased level by ceasing to withhold capacity. This ability to decrease prices from an increased level is different from suppressing prices below the competitive level, which appears to be the concern Dr. Morris addresses in his discussion of a price floor for PJM East prices.[57]

Q. **Dr. Morris argues that the merged entity could not benefit from greater price volatility because the utilities hedge their electric power and their natural gas positions. Do you agree?**

---

54 For example, when storage inventory level is high, the maximum withdrawal rate is high and the maximum injection rate is low. When storage inventory is low, the opposite restrictions apply, the maximum withdrawal rate is reduced while the maximum injection rate is increased.

55 On some of its storage contracts, PSEG also has restrictions on the average withdrawal rate not exceeding 87.5% or 92% of its maximum daily withdrawal quantity over a 30-day period. PECO Energy Response to Data Request PGW VI-9. However, these restrictions only encourage day-to-day variability in withdrawal rate, where a day of high withdrawals would be followed by a day of lower withdrawals.

56 PECO Energy response to Data Request PGW VI-9.

57 PECO Statement No. 11-R, Rebuttal Testimony of John R. Morris, pages 40-43.

A. No. First, Dr. Morris provides no support for his argument beyond his statement that "Both utilities hedge their electric power positions and their natural gas positions." But, even if it were true, this does not mean that the merged entity could not profit by selling gas and electricity financial instruments. Increasing the volatility of natural gas prices, and therefore the volatility of electricity prices, will tend to increase the price of options contracts for any given natural gas or electricity price level. The merged entity will have the ability to increase the volatility of natural gas and electricity prices in PJM East, and its unregulated power and gas trading division can profit from this increased volatility by trading in gas and electricity financial futures and options markets.

Q. Dr. Morris argues that in the long-run, significantly more supply options will be available to counteract withholding by the merged entity. He names a number of proposed East Coast LNG facilities. Can the Commission rely on these proposed East Coast LNG facilities to add supply to the PJM East gas market?

A. No. There is significant uncertainty surrounding all of the LNG facilities discussed by Dr. Morris:

- ***Weaver's Cove in Fall River, MA***: This project faces strong local opposition. Since June 30, 2005, when Weaver's Cove received its FERC permit, a provision was inserted into federal transportation legislation by a Massachusetts congressman to prevent the removal of a bridge that must be replaced in order for LNG tankers to deliver to Weaver's Cove.[58] And, the U.S. Navy asked FERC to reconsider its decision to permit Weaver's Cove. The Navy contends that FERC did not consider the LNG terminal's impact on Naval operations in the area.[59]
- ***Crown Landing LNG in New Jersey***: The State of New Jersey appears to be strongly in favor of this project. In fact, the New Jersey BPU supports the Crown Landing project "as a means to increase the vital supply of natural gas to New

58 "Lawmakers insert language to kill LNG project," *Gas Daily*, August 4, 2005.
59 "Navy objects to Weaver's Cove LNG proposal," *Gas Daily*, August 17, 2005.

Jersey." However, the Delaware Dept. of Natural Resources denied a permit for a pier into the Delaware River that was to accommodate tankers at the facility.[60]

The PSEG Companies (including PSE&G and PSEG ER&T) protested Crown Landing at FERC on gas quality grounds and because LNG tankers making deliveries to Crown Landing would pass the site of PSEG's Salem and Hope Creek nuclear plants.[61] PSEG asked FERC to reject Crown Landing's application until these issues are resolved. It suggested that one way to resolve the gas quality issue (if LNG processing is not economic in New Jersey) is to locate Crown Landing along the U.S. Gulf Coast. PSEG later asked FERC not to allow Crown Landing to become operational until "sufficient insurance coverage is in place to protect third parties against loss in the event an accident were to occur during the transport or storage of LNG."[62]

- ***Broadwater Energy LNG in Long Island Sound, NY:*** This project also faces significant local opposition, particularly from the Governor of Connecticut and Suffolk County, NY.[63]
- ***Canaport and Bear Head LNG in Eastern Canada***: Industry consensus as reflected in trade press reports is that the Canaport and Bear Head LNG facilities are the most likely East Coast LNG facilities to come on line. Construction of Bear Head has started. However, even these two projects are not a certainty. Moody's recently downgraded bonds issued by Maritimes & Northeast Pipelines LLC, which had previously entered into precedent agreements to transport gas volumes from the Canaport and Bear Head facilities. In a press release announcing the downgrade, Moody's described Maritimes' planned expansion to

60 "N.J. to sue Delaware over LNG plant jurisdiction," *Gas Daily*, July 29, 2005.

61 "Motion to Intervene, Comments and Protest of the PSEG Companies," October 20, 2004, FERC Docket No. CP04-411.

62 Comments from the PSEG Companies, April 18, 2005, FERC Docket No. CP04-411.

63 See "Conn. Governor joins anti-Broadwater lobby," *Gas Daily*, August 12, 2005, and "Suffolk County formally opposes planned Long Island LNG terminal," *Gas Daily*, May 18, 2005.

accommodate volumes from Canaport and Bear Head as "uncertain and subject to revision at this early stage."[64]

- PGW's own proposed LNG Terminal Project is at a very early stage, and it is premature to offer an opinion on its political or regulatory viability.

Q. Dr. Morris argues that the New Jersey Board of Public Utilities has the same regulatory oversight of PSEG ER&T's gas costs and acquisition practices as it did before PSEG ER&T assumed PSE&G's gas procurement operations. Do you agree?

A. No, I do not. Dr. Morris asserts that the New Jersey BPU's oversight of PSEG ER&T's gas procurement activities is "similar" to this Commission's oversight of PECO. However, the New Jersey BPU does not regulate PSEG ER&T. It only has authority over PSEG ER&T through the terms and conditions of the PSE&G/PSEG ER&T BGSS Full Requirements contract, since it has authority over PSE&G's procurement of BGSS gas supply.

Data responses submitted by PSE&G in the New Jersey BPU proceeding acknowledge this difference.[65] These data responses (appended to this testimony as Appendices 1, 2 and 3) are admissions by PSE&G that the New Jersey BPU's regulatory reach does not extend past the regulated operations of PSE&G to the unregulated decisions of ER&T.

IV. REMEDIES

Q. How did Exelon and PECO respond to your suggested remedies to mitigate the vertical market power problems created by the proposed merger?

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[64] See "Moody's Downgrades the Ratings of Maritimes & Northeast Pipeline and Martimes & Northeast Pipeline Limited Partnership (Both to A2 from A1, Sr. Sec.); Rating Outlook is Stable," from Moody's Investors Service website, August 3, 2005.

[65] PSE&G Responses to Data Requests RAR-GAS-22, RAR-GAS-22 (Revised) and RAR-GAS-33 in New Jersey BPU Proceeding No. EM05020106.

A. Dr. Hieronymus did not respond in any way to my suggested remedies. Dr. Morris submitted one question and answer in which he averred that my first suggested remedy, the divestiture of PECO and PSE&G's gas operations "has no nexus to the alleged problem." He suggests that there would be "less intrusive" remedies available, but does not suggest what they might be. Dr. Morris completely ignores my second remedy which involves the transfer to an independent third party of the upstream capacity rights held by PSEG ER&T and PECO gas, with significant regulatory oversight of the use of those rights.

Q. Would the divestiture remedy solve the problem you have identified?

A. Yes. Divestiture of the gas operations of PECO and PSE&G would separate the *ability* of the merged entity to exercise market power from its *incentive* to do so. As I stated in my direct testimony, it is the cleanest approach to solving the problem with the least regulatory oversight required, and it is the method traditionally favored by enforcement agencies such as the U.S. Department of Justice and the FTC.

Q. Mr. Arndt, in his rebuttal testimony for Exelon, suggests that you have ignored the costs of divestiture in your discussion of remedies. What is your response?

A. First, as I mentioned in response to Dr. Morris' testimony on remedies, I proposed two remedies, only one of which would require divestiture.

More importantly, what Mr. Arndt is apparently suggesting is that the Commission accept some competitive harm from the merger in exchange for slightly lower costs to customers in the future. I do not believe the Commission should make such a trade-off. My understanding of the Commission's obligations in reviewing a merger application is described on pages 9 and 10 of my direct testimony. As I understand it, the Commission cannot approve proposed transactions that it views as likely to be harmful to retail gas and electricity markets except upon such terms as it finds necessary to preserve the benefits of competition.

V. DIRECTED QUESTIONS

Q. What is your response to Directed Question 1, which asks: "Neighboring states have availed themselves of opportunities to enhance their economic competitiveness through access to economical energy resources. What opportunities exist from this proposed merger in terms of economic development for Pennsylvania? Specifically, does this proposed merger present us with an opportunity to strengthen the State's ability to remain competitive during periods of economic recession and volatile energy pricing?"

A. My analysis indicates that, if left unremedied, this proposed merger is likely to substantially weaken Pennsylvania's ability to enhance its competitiveness with respect to access to economical energy resources, and it is likely to increase the level and volatility of natural gas and power prices in the State. As proposed, the merger would create an entity that has market power in the natural gas markets that serve important regions of Pennsylvania. Moreover, the merger creates powerful incentives for the merged entity to leverage that power into the PJM East electricity market. The creation of an entity with such a dominant position in Pennsylvania's gas and power markets will make it even more difficult for the state to successfully create and sustain a competitive retail market in electricity.

Q. What is your response to the fifth Directed Question, which asks: "Would the combination of the PSE&G gas division with the PECO gas division and the Philadelphia Gas Works provide critical mass for a viable, profitable, shareholder owned public utility, assuming a revenue stream from off system sales from an LNG facility, and separate resolution of the problem of a billion dollar debt?"

A. My response to this question is in connection with the divestiture remedy that I suggested to mitigate the vertical market power problem created by the merger.

First, I assume that the question is asking about the combination of PGW, and the PECO and PSE&G gas divisions outside of ownership by Exelon. Otherwise, there would be no cure for the vertical market power problem I have identified.

Second, the combination of PECO and PSE&G's gas divisions (with or without PGW) should not be considered without fully assessing whether such a merger would create horizontal market power problems in the natural gas market. Such a combination would also likely create some challenges for the coordination of state regulatory jurisdiction of the combined entity that would need to be resolved in advance.

However, a remedy that involved the divestiture of the PSE&G and PECO gas divisions into separate entities (such as I have proposed), and the combination of PECO Gas with PGW, would not likely create any horizontal market power problems in the natural gas market (assuming continued regulation of that entity by the Commission), and would certainly mitigate any vertical market power problems created by the proposed merger of Exelon and PSEG.

Q. Having reviewed the initial filing, the discovery, and the rebuttal testimony, what final conclusions do you draw from this merger proposal?

A. The opinion I offered in my direct testimony has not changed. In fact, the additional analysis that I have performed in response to the petitioning parties' rebuttal testimony simply reinforces my conclusion that this merger as proposed has the potential to distort the electricity and gas markets that directly affect Pennsylvania and the surrounding region. Such distortions could prove very costly to ratepayers and the local economy. I have no basis to believe that such is the intent of the petitioners, only that management of the merged company would have the ability and the incentive to take such actions that could have that effect. It is therefore my strong recommendation that this Commission reject the merger as proposed.

Q. Does this complete your surrebuttal testimony?

A. Yes, it does.

APPENDIX 1

Frances I. Sundheim
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PSEG

March 29, 2005

In The Matter Of The Joint Petition Of
Public Service Electric And Gas Company
and Exelon Corporation
For Approval Of A Change In Control Of
Public Service Electric And Gas Company,
and Related Authorization

BPU Docket No. EM05020106
OAL Docket No. PUC-1874-05

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Dear Ms. Comes and Ms. Morita:

Attached are the Joint Petitioners' responses to following requests for information:

RAR-CS-1	-	Capital Structure - Cost of Equity
RAR-CS-2	-	Capital Structure - Cost of Equity
RAR-CS-4	-	PSEG Capital Structure Objectives
RAR-CS-5	-	Capital Structure
RAR-CS-6	-	SEC Filings
RAR-CS-7	-	Form 10Q, 10K, Annual Report and Security Analyst Presentations
RAR-CS-8	-	Credit Rating Reports
RAR-CS-11	-	12/31/04 Balance Sheet & Capitalization
RAR-CS-12	-	Embedded Cost Schedule
RAR-CS-13	-	Short-Term Debt
RAR-CS-14	-	Short-Term Interest Rate
RAR-CS-16	-	Financing Due to Merger
RAR-CS-17	-	Financing Plan
RAR-CS-18	-	Dividend Policy
RAR-CS-21	-	Money Pool
RAR-CS-22	-	Money Pool
RAR-CS-23	-	Money Pool
RAR-CS-24	-	SEC Filings

RAR-GAS-1	-	Requirements Contract
RAR-GAS-2	-	Transfer of Capacity Contracts
RAR-GAS-3	-	Requirements Contract - Merger Impact
RAR-GAS-4	-	Gas Distribution Function After the Merger
RAR-GAS-5	-	ER&T - Gas Procurement Staff
RAR-GAS-6	-	Gas Service Metrics
RAR-GAS-7	-	Gas Pipeline and Storage Capacity
RAR-GAS-11	-	Gas Supply Capacity
RAR-GAS-12	-	Capacity - First Refusal Rights
RAR-GAS-13	-	Capacity Rights
RAR-GAS-14	-	BPU Oversight Authority
RAR-GAS-15	-	Off-System Sales Sharing
RAR-GAS-16	-	Supply Preference - Generation
RAR-GAS-17	-	Allocation Methodology
RAR-GAS-18	-	Gas Price Hedging
RAR-GAS-19	-	Full Requirements Contract
RAR-GAS-22	-	BPU Oversight Authority
RAR-GAS-23	-	Gas Distribution Function After the Merger

Very truly yours

Frances I. Sundheim

Attachments
C Attached Service List

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

BPU OVERSIGHT AUTHORITY

QUESTION:
After the merger, will the Board continue to have on-going authority for review and control of gas procurement by ER&T (or any comparable successor entity)?

ANSWER:
The Merger will not affect the existing oversight authority of the Board over the Requirements Contract. The Board will continue to have authority over gas procurement by ER&T or any comparable successor entity.

APPENDIX 2

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PSEG

April 13, 2005

In The Matter Of The Joint Petition Of
Public Service Electric And Gas Company
and Exelon Corporation
For Approval Of A Change In Control Of
Public Service Electric And Gas Company,
and Related Authorization

BPU Docket No. EM05020106
OAL Docket No. PUC-1874-05

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Dear Ms. Comes and Ms. Morita:

Attached are the Joint Petitioners' responses to following requests for information:

RAR-CS-19 - Money Pool
RAR-GAS-12 (Revised) - Capacity - First Refusal Rights
RAR-GAS-22 (Revised) - BPU Oversight Authority
RAR-LI-48 - PSE&G Customer Accounts, CS&I and Sales Expenses
* RAR-LI-73 - Low Income Residential Energy Efficiency Programs
RAR-LI-74 - Weatherization Assistance Program
RAR-LI-75 - Effectiveness of Low Income Energy Efficiency Programs
RAR-SQ-1 - Merger Impacts on PSE&G Rates
RAR-SQ-2 - High Quality Service & Best Operating Practices
RAR-SQ-25 - Operational Capability
S-AUD-1 - Regulatory Reports
S-AUD-2 - Internal Audits
S-AUD-5 - Exelon Annual Reports
S-AUD-6 - Exelon Stockholder Reports
S-AUD-7 - Exelon 10K Filings
S-AUD-8 - Exelon Balance Sheet
S-AUD-9 - Exelon Income Statement
S-AUD-10 - Exelon Statement of Cash Flows

S-AUD-11	-	Exelon Stockholder's Equity
S-AUD-12	-	Tax Returns
S-AUD-13	-	Accounting for Change in Ownership
S-AUD-16	-	Board of Director Minutes
S-AUD-17	-	Outside Legal Counsel
S-AUD-19	-	Exelon Outside Accounting Firms
S-AUD-20	-	Exelon External Accounting/Financial Firms
S-AUD-21	-	Exelon Accounting Systems
S-AUD-26	-	Exelon Accounts Receivables With Subsidiaries and Affiliates
S-AUD-27	-	Exelon Affiliate Accounting Procedures
S-AUD-29	-	Exelon Segment Reporting
S-AUD-30	-	Exelon Financial Derivatives
S-AUD-40	-	FAS 141 Requirements

* Due to the bulk of these responses, copies are being provided to those shown below. Any other parties wishing to inspect this material may do so at the Company's Offices at a mutually convenient time.

Very truly yours

James P. Burdi

Attachments
C Attached Service List

RAR-LI-73
Alice Bator
Margaret Comes, DAG
James Giuliano
Fred Grygiel
Ami Morita, Esq. (6 copies)
Mark Mucci-Exelon, Esq.
Kent Papsun
Walter Szymanski

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

BPU OVERSIGHT AUTHORITY

QUESTION:
After the merger, will the Board continue to have on-going authority for review and control of gas procurement by ER&T (or any comparable successor entity)?

ANSWER:
The Merger will not affect the existing oversight authority of the Board over the Requirements Contract. ER&T or any comparable successor entity will still provide gas procurement for BGSS supply.

APPENDIX 3

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PSEG

July 13, 2005

In The Matter Of The Joint Petition Of
Public Service Electric And Gas Company
and Exelon Corporation
For Approval Of A Change In Control Of
Public Service Electric And Gas Company,
and Related Authorization

BPU Docket No. EM05020106
OAL Docket No. PUC-1874-05

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Dear Ms. Comes and Ms. Morita:

Attached are the Joint Petitioners' responses to following requests for information:

RAR-GAS-31	-	Requirements Contract - Rights
RAR-GAS-32	-	Requirements Contract - Terms & Conditions
RAR-GAS-33	-	Requirements Contract - Oversight
RAR-GAS-34	-	Margins on Capacity Transactions
RAR-GAS-35	-	Residential vs. C&I Allocation Methodology
RAR-GAS-36	-	Requirements Contract - Rights
RAR-GAS-37	-	Requirements Contract - Rights
RAR-GAS-38	-	Requirements Contract - Default by Seller
RAR-GAS-39	-	Requirements Contract - Default
RAR-GAS-40	-	Requirements Contract - Force Majeure
RAR-GAS-41	-	Requirements Contract - Obligation to Curtail
RAR-GAS-42	-	Requirements Contract - Right to Audit
RAR-RR-85	-	PSEG Directors - 3 Year Transition Period
RAR-RR-86	-	Board of Directors – Transition Period
RAR-RR-88	-	Charitable Contributions
RAR-RR-92	-	Cost Allocation Methodology - MMF
RAR-RR-95	-	Exelon BGS Charges
*** RAR-SQ-154	-	Exelon Internal Audits
*** RAR-SQ-155	-	Exelon Internal Audits

95-5048

*** RAR-SQ-156	-	Exelon Internal Audits
*** RAR-SQ-157	-	Exelon Internal Audits
*** RAR-SQ-158	-	Exelon Internal Audits
* S-CEP-EE-1	-	Energy Efficiency Programs
S-ENE-EMP-22(Update)	-	Pension & Benefits Packages
S-ENE-EMP-25(Update)	-	Employee Levels Since Announcement of the Merger
S-ENE-NUC-1(Revised)	-	Nuclear Facilities Ownership
S-ENE-REL-14	-	Safety Results

* Due to the bulk of this response, copies are being provided to those shown below. Any other parties wishing to inspect this material may do so at the Company's Offices at a mutually convenient time.

*** Please note that these responses are Confidential and are only being supplied to those shown below as indicated. These documents are highly Confidential. They must be treated in a manner that complies with and abides by the terms set forth in the Confidentiality Agreement, including but not limited to the proper security and control protocols for the appropriate handling, filing, storage, dissemination and return of the Confidential documents..

Very truly yours,

James P. Sundl

C Attached Service List

<u>RAR-SQ-154</u>
<u>RAR-SQ-155</u>
<u>RAR-SQ-156</u>
<u>RAR-SQ-157</u>
<u>RAR-SQ-158</u>
Nancy Brockway
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Howard Lubow
Mark Mucci-Exelon, Esq.
Kent Papsun
Suzanne Patnaude
David Robinson **
Dean Taklif
Bud Ubushin, Esq.
Susan Vercheak, DAG
J.P. Villamizar

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REQUIREMENTS CONTRACT - OVERSIGHT

QUESTION:
(Re: RAR-GAS-14) The Board currently has oversight and the right to review and audit ER&T's operations. Will such Board authority continue for ER&T or its successor? Full oversight for purposes of this request is not limited to just the terms of the Requirements Contract.

ANSWER:
PSE&G disagrees with the premise of the question. The Board does not have jurisdiction over ER&T's operations as such. The Board has the authority to review the terms and conditions pursuant to which PSE&G procures gas supply. The merger will not affect the extent of the Board's oversight and review authority in this regard.

PGW Statement No. 1-S
Docket No. A-110550F0160
Witness: Paul R. Carpenter

9/23/05 Phila
TK

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

SUPPLEMENTAL TESTIMONY OF

PAUL R. CARPENTER

DOCUMENT
FOLDER

ON BEHALF OF
PHILADELPHIA GAS WORKS

In Opposition to the Joint Settlement Petition

Docket No. A-110550F0160

Joint Application of PECO Energy Company and Public Service
Electric And Gas Company for Approval of the Merger of Public
Service Enterprise Group Incorporated with and into Exelon Corporation

September 20, 2005

I. INTRODUCTION

Q. Dr. Carpenter, have you previously filed testimony in this proceeding?

A. Yes, I filed direct testimony on June 27, 2005 that showed that the proposed Exelon/PSEG merger raises significant vertical market power concerns. I also filed surrebuttal testimony on August 26, 2005 that principally responded to rebuttal testimony submitted by Dr. William Hieronymus and Dr. John Morris on behalf of Exelon and PSEG.

Q. What is the purpose of this supplemental testimony?

A. PGW has asked me to review and comment on the Joint Settlement Petition filed on September 12, 2005 in this proceeding as it relates to market power issues. The Joint Settlement was entered into between the Joint Applicants, PECO Energy and PSE&G, and a group of intervening parties in this proceeding. To my knowledge, PGW, the City of Philadelphia, PPL and First Energy are not parties to this Settlement.

Q. The Petitioners state at page 2 of the Settlement that it "resolves all issues in the above-captioned Joint Application"... and that "this comprehensive settlement is in the public interest" such that the Commission can and should approve the merger. Do you agree?

A. No, I do not. This Settlement is a partial settlement only, and it does not address in any way the vertical market power issues that I have raised in my prior two pieces of testimony. In this supplemental testimony, I describe how this Settlement fails to address the vertical market power problem I previously identified.

II. THE JOINT SETTLEMENT DOES NOT MITIGATE THE MERGED ENTITY'S MARKET POWER IN THE PJM EAST NATURAL GAS MARKET

Q. In your direct and surrebuttal testimony in this proceeding you showed how the merged entity would possess market power in the PJM East natural gas market and how the merger would create a strong incentive to exercise that market power. Does the Joint Settlement protect customers from the exercise of market power by the merged entity in the PJM East gas market?

A. *No, it does not. In fact, the Settlement does not even refer to competitive issues in the* PJM East natural gas market. The only reference made in the Settlement document to market power issues is in Section I (page 29) entitled "Competitive Electric Markets." There is no mention in that section of the document of any measures that the parties agreed to that are designed to protect the electricity market from potential market power abuses by the merged entities in the natural gas market. As I described in my prior testimony in this proceeding, there is a direct linkage between the price of natural gas and the price of electricity during many hours of the year. In the context of this merger, it is not possible to ensure that the wholesale and retail electricity markets are competitive without ensuring that the natural gas market is also competitive.

Q. The Settlement contains provisions meant to protect PECO's customers from Affiliate Risk and Cross-Subsidization (section F of the Joint Settlement, and in particular paragraphs 43, 45 and 46). Will these provisions prevent the merged entity from exercising market power in the PJM East gas market?

A. No. These provisions are very limited. They do not give this Commission the ability to monitor the gas market activities of the merged entity's unregulated gas market affiliates. Moreover, the Settlement does not require the Applicants to maintain separate gas procurement operations for PECO and PSE&G. As I explained in direct testimony, the Applicants have stated that they do not intend to combine their gas procurement operations. However, I am not aware of any commitment made by the

Applicants not to combine the gas procurement functions of PECO and PSE&G (which is now performed by its unregulated affiliate PSEG ER&T). The settlement does not contain any such commitment.

III. THE JOINT SETTLEMENT DOES NOT PROVIDE ANY ADDITIONAL PROTECTION TO MITIGATE THE MERGED ENTITY'S MARKET POWER IN PJM ELECTRICITY MARKETS

Q. Does the Joint Settlement protect customers from the exercise of market power by the merged entity in the PJM East electricity market?

A. The Joint Settlement contains provisions in "Section I. Competitive Electric Markets" that are meant to protect customers from the exercise of market power in the PJM East electric market. But these provisions offer customers no additional and effective protection from the exercise of market power.

For example, the Joint Settlement requires PECO to file an annual report with this Commission in 2007 – 2012 "addressing wholesale market prices and price trends in the Pennsylvania-New Jersey-Maryland Interconnection ("PJM") markets."[1] The report is to contain "information regarding price differentials between PJM East and other PJM regions and other information necessary to assess price and price trends in the PJM markets." All of the information referred to in this section involves the prices for electricity as opposed to natural gas.

Q. Is there anything new about this electricity price reporting requirement?

A. Not as I interpret it. This price report does not give the Commission any information it does not already have access to on the PJM website. And more importantly, it does not give the Commission access to any additional information that would be useful in determining whether Exelon's affiliates were exercising market power in the PJM East electricity market.

[1] Joint Settlement, page 29, paragraph 53a.

The annual report required of PECO does not give the Commission any electricity price information it does not already have access to. The "information regarding price differentials between PJM East and other PJM regions" that PECO would be required to include in its annual report is already publicly available on the PJM website.[2] The additional information required to be included in PECO's annual report ("other information necessary to assess price trends in the PJM markets") is so vague as to be meaningless. I would note that the Commission currently has access to an annual report on PJM electricity markets prepared by the PJM Market Monitor that is more comprehensive than the report required of PECO in the Joint Settlement.[3]

Even if the information were better specified, it should be recognized that it is extremely difficult to detect the exercise of market power after the fact by simply looking at price differential data, because it is very difficult to distinguish between high price levels and differentials that are the result of an exercise of market power and those that are the result of naturally tight supply and demand conditions in particular locations. This is one reason why structural remedies are the preferred means to mitigate market power in merger situations.[4]

Q. The Joint Settlement also permits a party to the Settlement (a "Joint Petitioner") to request that the Commission initiate an investigation when the Joint Petitioner reasonably believes that an affiliate of PECO has unlawfully exercised market power in PJM markets (paragraph 53b). Does this provision mitigate the market power that will be possessed by the merged entity?

A. No, it does not. First, it is my understanding that parties already have the authority to file a complaint or to ask the Commission to initiate an investigation, since it is difficult to imagine an effective regulatory system that would not permit such

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[2] Daily Day Ahead price data for PJM East and other PJM Hubs is available on the PJM website at http://www.pjm.org/markets/jsp/lmpda.jsp. Daily Real Time price data for PJM East and other PJM Hubs is available on the PJM website at http://www.pjm.org/markets/jsp/lmp.jsp.

[3] The PJM Market Monitor's most recent public annual report on PJM electricity markets, the 2004 PJM State of the Market Report, is available on the PJM website at http://www.pjm.org/markets/market-monitor/som.html.

complaints, so the Settlement adds nothing new in this area. Second, the Settlement does not establish with any specificity what threshold level or type of information is required in order for a Joint Petitioner to show that it "reasonably believes" that PECO's affiliated generation company has unlawfully exercised market power. Again, if a merger creates a risk that market power could be exercised, it is best to mitigate it through structural remedies prior to approving the merger than to rely on the possibility of after-the-fact investigation to deter its exercise.

IV. THERE ARE SIGNIFICANT RISKS FROM NOT ADDRESSING THE MERGED ENTITY'S GAS AND ELECTRICITY MARKET POWER

Q. What are the potential impacts of the proposed merger on electricity customers in PJM East if the Commission accepts the Joint Settlement as proposed, and approves the merger?

A. The Settlement offers customers a decrease in PECO's retail electric distribution rates of $40.0 million annually for two years after the merger closes, and then $20.0 million annually for an additional two years, for a total rate reduction of $120.0 million (nominal) over 4 years.[5] The Settlement also caps PECO's T&D and generation charges for four years, from January 1, 2007 to December 31, 2010.[6] The rate reductions amount to $1.26 per month for a typical residential customer for two years, and $0.63 per month for a typical residential customer for an additional two years.[7] Other rate classes also receive rate reductions. The Settlement also offers a number of other provisions (such as reliability, environmental, corporate presence, and other provisions) whose benefits to customers are not easily quantifiable, and in

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4 See Section III.A. of the "Antitrust Division Policy Guide to Merger Remedies," U.S. Department of Justice, Antitrust Division, October 2004.

5 Joint Settlement, pages 8-10, paragraph 14.

6 Joint Settlement, page 10, paragraph 15.

7 These residential customer savings assume usage of 700 kWh per month on an annual basis. They are calculated as (700 kWh x $0.0018/kWh savings) for the first two years, and (700 kWh x $0.0009/kWh savings) for an additional two years. See Appendix A to the Joint Settlement, "PECO Energy Co., 2006 Unbundled Unit Rates (¢/kWh)" and "PECO Energy Co., 2008 Unbundled Unit Rates (¢/kWh)."

and other provisions) whose benefits to customers are not easily quantifiable, and in some cases (e.g., reliability) are not obvious improvements over what a regulated utility would be required to meet as a feature of standard regulatory oversight.

The risks to customers from an exercise of market power are potentially much greater than the rate reductions offered by the Settlement. These risks are in the form of higher price levels for natural gas and electricity than would otherwise be the case, and greater price volatility which increases costs for gas and electricity ratepayers in ways that are difficult to quantify in advance but potentially significant.

Q. Do you have any concerns about the short duration of the electricity price reporting requirements and the customer discounts?

A. Yes, I do. While the benefits contained in this Settlement agreement are short-term in duration, the merged entity itself will likely be with us for a very long time. Because it is very difficult to undo a merger once it has been completed I urge the Commission not to approve the merger unless there is adequate mitigation to resolve the vertical market power problem it presents.

Q. Does this complete your supplemental testimony?

A. Yes, it does.

ATTACHMENT M

PJM MARKET MONITORING PLAN

I. OBJECTIVES

The objectives of this Market Monitoring Plan are to: (1) monitor and report on issues relating to the operation of the PJM Market, including the determination of transmission congestion costs or the potential of any Market Participant(s) to exercise market power within the PJM Region; (2) evaluate the operation of both pool and bilateral markets to detect either design flaws in the PJM Market operating rules, standards, procedures, or practices as set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the Reliability Assurance Agreement-West, the PJM Manuals, or PJM Regional Practices Document or to detect structural problems in the PJM Market that may need to be addressed in future filings; (3) evaluate any proposed enforcement mechanisms that are necessary to assure compliance with pool rules; and (4) ensure that the monitoring program will be conducted in an independent and objective manner. The Plan also prescribes reporting procedures that PJM will use to inform governmental agencies and others concerning its market monitoring activities.

Consistent with the PJM Operating Agreement, PJM will carry out these objectives in a manner consistent with the safe and reliable operation of the PJM Region, the creation and operation of a robust, competitive, and non-discriminatory electric power market in the PJM Region, and the principle that a Member or group of Members shall not have undue influence over the operation of the PJM Market.

This Plan applies to PJM, Market Participants, and all entities that take service under the PJM Tariff.

II. DEFINITIONS

Unless the context otherwise requires, for purposes of this Plan, capitalized terms shall have the meanings given below or in Section I of the PJM Tariff.

(a) "**Authorized Government Agency**" means a regulatory body or government agency, with jurisdiction over PJM LLC, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, state utility commissions, and state and federal attorneys general.

(b) "**Corrective Action**" means an action set forth in section IV of this Plan.

(c) "**Market Monitoring Unit**" means the organization within PJM that is responsible for implementing this Plan.

(d) "**Market Participant**" means an entity that generates, transmits, distributes, purchases, or sells electricity or provides ancillary services with respect to such services (or contracts to perform any of the foregoing activities) within, into, out of, or through the PJM Region.

(e) **"PJM"** means the Office of the Interconnection of PJM LLC.

(f) **"PJM Board"** means the Board of Managers of PJM LLC or its designated representative.

(g) **"PJM Entities"** means PJM, including the Market Monitoring Unit, the PJM Board, and PJM LLC's officers, employees, representatives, advisors, contractors, and consultants.

(h) **"PJM LLC"** means the PJM Interconnection, L.L.C.

(i) **"PJM Manuals"** means those documents produced by PJM that describe detailed PJM operating and accounting procedures that are made publicly available in hard copy and on the Internet.

(j) **"PJM Market"** means the PJM Interchange Energy Market together with all bilateral or other electric power and energy transactions, ancillary services transactions, and transmission transactions within the PJM Region.

(k) **"PJM Operating Agreement"** means the Amended and Restated Operating Agreement of PJM LLC on file with FERC.

(l) **"PJM Regional Practices Document"** means the document of that title that compiles and describes the practices in the PJM Market and that is made available in hard copy and on the Internet.

(m) **"PJM Reliability Assurance Agreement"** means the Reliability Assurance Agreement among Load Serving Entities in the PJM Control Area on file with the FERC.

(n) **"Reliability Assurance Agreement-West"** means the "PJM West Reliability Assurance Agreement Among Load Serving Entities in the PJM West Region" on file with the Commission.

(o) **"PJM Tariff"** means the Open Access Transmission Tariff of PJM LLC on file with FERC.

(p) **"Plan"** means the PJM market monitoring plan set forth in this Attachment M.

(q) **"President"** means the President and Chief Executive Officer of PJM LLC.

III. MONITORED ACTIVITIES

The Market Monitoring Unit shall be responsible for monitoring the following:

A. Compliance with the rules, standards, procedures, and practices of the PJM Market set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Manuals, and the PJM Regional Practices Document.

B. Actual or potential design flaws in the PJM Market operating rules, standards, procedures, and practices set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Manuals, and the PJM Regional Practices Document and structural problems in the PJM Market that may inhibit a robust and competitive market.

C. The potential of any Market Participant(s) to exercise undue market power.

IV. CORRECTIVE ACTIONS

A. **Required Reporting to Commission:** The Market Monitoring Unit shall notify the Commission immediately upon determining that it has identified a significant market problem that may require (a) further investigation, (b) a change in the PJM Tariff or PJM Market operating rules, standards, procedures, and practices set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Manuals, and the PJM Regional Practices Document, or (c) action by the Commission and/or one or more state commissions.

B. **Additional Market Monitoring Unit Authority:** The Market Monitoring Unit may take the following additional actions, to the extent it deems necessary, as a result of its monitoring activities:

1. Engage in discussions to bring issues concerning PJM Market operating rules, standards, procedures, or practices to the attention of Market Participants and attempt to resolve informally compliance or other issues with Market Participants.

2. Recommend to the appropriate entity (including, if and as appropriate, PJM committees, the PJM Board, or the Commission) modifications to the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Manuals, or other PJM rules, standards, practices, or procedures.

3. Through demand letter, request a Market Participant(s) to discontinue actions that the Market Monitoring Unit believes violate the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the Reliability Assurance Agreement-West, the PJM Manuals, or other rules, standards, practices, or procedures concerning the operation of the PJM Market. The Market Monitoring Unit shall provide such demand letters to the relevant Authorized Government Agencies, subject to the protection of confidential, proprietary, and commercially sensitive information.

4. If unable to achieve sufficient correction action on matters through informal discussions or demand letter, and if and as appropriate and necessary, bring matters to the attention of, and make appropriate recommendations for action to, the Members Committee, other PJM Committees, or the PJM Board.

5. With the approval of the PJM Board, file reports or complaints with Authorized Government Agencies or make other appropriate regulatory filings to address design flaws, structural problems, compliance, market power, or other issues, and seek such remedial measures or make such recommendations as the Market Monitoring Unit shall deem appropriate. The Market Monitoring Unit also shall consult with Authorized Government Agencies concerning the need for specific investigations or monitoring activities.

6. Consider and evaluate a broad range of additional enforcement mechanisms that may be necessary to assure compliance with PJM's rules, standards, procedures, and practices. As part of this evaluation process, the Market Monitoring Unit shall consult with Authorized Government Agencies and other interested parties.

C. ***Confidentiality:***

1. All discussions between the Market Monitoring Unit and Market Participants concerning the informal resolution of compliance issues and all demand letters sent to Market Participants initially shall remain confidential.

2. Except as provided in subsection 3, in exercising its authority to take Corrective Actions, the Market Monitoring Unit shall observe the confidentially provisions of the PJM Operating Agreement.

3. Notwithstanding anything to the contrary in this Plan or the PJM Operating Agreement, the Market Monitoring Unit: (a) may disclose any information to the Commission in connection with the reporting required under section IV.A of the Plan, provided that any written submission to

the Commission that includes information that is confidential under the PJM Operating Agreement shall be accompanied by a request that the information be maintained as confidential, and (b) may make reports, complaints, or other regulatory filings pursuant to section IV.B.5 of this Plan if accompanied by a request that information that is confidential under the PJM Operating Agreement be maintained as confidential.

V. MARKET MONITORING UNIT

A. **Establishment**: PJM shall establish, and provide appropriate staffing and resources to, the Marketing Monitoring Unit, an organization within PJM that shall be responsible for implementing this Plan.

B. **Composition**: The Market Monitoring Unit shall be comprised of full-time employees of PJM LLC having the experience and qualifications necessary to implement this Plan. In carrying out its responsibilities, the Market Monitoring Unit may retain such consultants and experts as it deems necessary, subject to the oversight of the President and/or the PJM Board.

C. **Accountability and Responsibilities**: The Market Monitoring Unit shall be accountable to the President and the PJM Board regarding the implementation of this Plan. The President shall ensure that the Market Monitoring Unit has adequate resources, access to required information, and cooperation of PJM for the effective functioning of the Market Monitoring Unit.

D. **Referral by President and Market Monitoring Unit**: To the extent that they deem desirable, the President and Market Monitoring Unit shall each have independent authority to refer any matters governed by this Plan to the PJM Board for review or approval.

VI. SPECIFIC MONITORING FUNCTIONS

A. **Primary Information Sources**: The Market Monitoring Unit shall rely primarily upon data and information that is customarily gathered in the normal course of business of PJM along with such publicly available data and information that may be helpful to accomplish the objectives of the Plan. The data and information available to the Market Monitoring Unit shall include, but not be limited to, information gathered or generated by PJM in connection with its scheduling and dispatch functions, its operation of the transmission grid in the PJM Region, its determination of Locational Marginal Prices, information required to be provided to PJM in accordance with the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, and the Reliability Assurance Agreement-West and any other information that is in the possession of PJM.

B. **Other Information Requests**: If other information is required, the Market Monitoring Unit shall comply with the following procedures:

1. <u>Request for Additional Data</u>: If the Market Monitoring Unit determines that additional information is required to accomplish the objectives of the Plan, the Market Monitoring Unit may request the entities possessing such information to provide the information on a voluntary basis. Any such request for additional information will be accompanied by an explanation of the need for the information and the Market Monitoring Unit's inability to acquire the information from alternate sources.

2. <u>Failure to Comply with Request</u>: The information request recipient shall provide the Market Monitoring Unit with all information that is reasonably requested. If an information request recipient does not provide requested information within a reasonable time, the Market Monitoring Unit may initiate such regulatory or judicial proceedings to compel the production of such information as may be available and deemed appropriate by the Market Monitoring Unit, including petitioning the Commission for an order that the information is necessary and directing its production. An information request recipient shall have the right to respond to any such petitions and participate in the proceedings thereon.

3. <u>Investigations of Undue Preference</u>: Notwithstanding subsection B.1, if the Market Monitoring Unit is investigating claims of possible undue preference between Transmission Owners and their affiliates, Transmission Owners and their affiliates must provide requested information to the Market Monitoring Unit within a reasonable time, as specified by the Market Monitoring Unit; provided, however, that an information request recipient may petition the Commission for an order limiting all or part of the information request, in which event the Commission's order on the petition shall determine the extent of the information request recipient's obligation to comply with the disputed portion of the information request.

4. <u>Confidentiality</u>: Except as provided in section IV.C.3 of this Plan, the Market Monitoring Unit shall observe the confidentiality provisions of the PJM Operating Agreement with respect to information provided under this section if an entity providing the information designates it as confidential.

C. <u>Complaints</u>: Any Market Participant or other interested entity may at any time submit information to the Market Monitoring Unit concerning any matter relevant to the Market Monitoring Unit's responsibilities under the Plan, or may request the Market Monitoring Unit to conduct an investigation or take any other action contemplated by the Plan. Such submissions or requests may be made on a confidential basis. The Market Monitoring Unit may request further information from such Market Participant or other entity and carry out any investigation that the Market Monitoring Unit considers appropriate. Neither the Market Monitoring Unit nor PJM Board shall be required to act with respect to any specific complaint unless the Market Monitoring Unit or, if appropriate, the PJM Board, determines action to be warranted.

D. <u>Collection and Availability of Information</u>: The Market Monitoring Unit shall regularly collect and maintain the information that it deems necessary for implementing the Plan. The Market Monitoring Unit shall make publicly available a detailed description of the categories of data collected by the Market Monitoring Unit. To the extent it deems appropriate and upon specific request, the Market Monitoring Unit may release other data to the public, consistent with PJM's obligations to protect confidential, proprietary, or commercially sensitive information.

E. <u>Market Monitoring Indices</u>: The Market Monitoring Unit shall develop, and shall refine on the basis of experience, indices or other standards to evaluate the information that it collects and maintains. Prior to using any such index or standard, the Market Monitoring Unit shall provide PJM Members, Authorized Government Agencies, and other interested parties an opportunity to comment on the appropriateness of such index or standard. Following such opportunity for comments, the decision to use any index or standard shall be solely that of the Market Monitoring Unit.

F. <u>Evaluation of Information</u>: The Market Monitoring Unit shall evaluate, and shall refine on the basis of experience, the information it collects and maintains, or that it receives from other sources, regarding the operation of the PJM Market or other matters relevant to the Plan. As so evaluated, such information shall provide the basis for reports or other actions of the Market Monitoring Unit under this Plan.

VII. <u>REPORTS</u>

A. <u>Reports to the PJM Board</u>: The Market Monitoring Unit shall prepare and submit to the PJM Board and, if appropriate, to the PJM Members Committee, periodic (and, if required, *ad hoc*) reports on the state of competition within, and the efficiency of, the PJM Market. In such reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The reports to the PJM Board shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.

B. <u>Reports to Government Agencies</u>: The Marketing Monitoring Unit shall contemporaneously submit to the Commission the reports provided to the PJM Board, subject to protection of confidential, proprietary and commercially sensitive information and the protection of the confidentiality of ongoing investigations and monitoring activities. Subject to the same provision regarding confidentiality, the Market Monitoring Unit also shall submit to other Authorized Government Agencies the reports provided to the PJM Board pursuant to Section VII.A. and other such reports, either as may be requested by such Agencies, or as may be deemed appropriate under Section IV.B.5.

C. <u>Public Reports</u>: The Market Monitoring Unit shall prepare a detailed public annual report about the Market Monitoring Unit's activities, subject to protection of confidential, proprietary, and commercially sensitive information and the protection of the confidentiality of ongoing investigations and monitoring activities.

VIII. <u>ANNUAL AUDIT</u>

The activities of the Market Monitoring Unit shall be audited in accordance with procedures adopted from time to time by the PJM Board.

IX. LIABILITY

Any liability of PJM arising under or in relation to this Plan shall be subject to this Section IX. The PJM Entities shall not be liable to any Market Participant, any party to the PJM Operating Agreement, any customer under the PJM Tariff, or any other person subject to this Plan in respect of any matter described in or contemplated by this Plan, as the same may be amended or supplemented from time to time, including but not limited to liability for any financial loss, loss of economic advantage, opportunity cost, or actual or consequential damages of any kind resulting from or attributable to any act or omission of any of the PJM Entities under this Plan.

X. OTHER RELIEF NOT FORECLOSED

A. **Preservation of Rights:** Nothing herein shall prevent PJM or any other person from asserting any rights it may have under the Federal Power Act or any other applicable law, statute, or regulation, including the filing of a petition with or otherwise initiating a proceeding before the Commission regarding any matter which is the subject of this Plan.

B. **Alternate Dispute Resolution:** Notwithstanding any provision of the PJM Tariff or the PJM Operating Agreement, PJM and the Market Monitoring Unit shall not be required to use the dispute resolution procedures in the PJM Tariff or the PJM Operating Agreement in carrying out its duties and responsibilities under this Plan. However, nothing herein shall prevent PJM or any other person from requesting the use of the dispute resolution procedure set forth in the PJM Tariff or the PJM Operating Agreement, as applicable.

XI. EFFECTIVE DATE

This Plan shall be effective as of the date it is accepted for filing by the Commission.

Section 8: Generator Deactivations

Welcome to the *Generator Deactivations* section of the PJM Manual for ***Generator Operational Requirements.*** In this section you will find the following information:

- Description of the PJM Deactivation Process.
- Methodology for compensation to Generators Required to Remain in Service for Reliability
- A process flow diagram for the process (See Exhibit 8.1).

Generator Deactivation Process

This section reviews the steps and timeline for the PJM generator deactivation process, and the potential results of the process. This section also reviews the methodology of compensation to generators requested to remain in service for reliability.

Generator Deactivation Request

Any generator owner, or designated agent, who wishes to retire a unit from PJM operations must initiate a deactivation request in writing to the PJM System Operations Generation Manager no less than 90 days in advance of the planned deactivation date. Black start resources require up to 2 years advanced notice to maintain the rolling 2 year commitment per the PJM tariff. This notice will include, at a minimum, the following information:

- Indication of whether the unit is being retired or mothballed;
- The desired date of deactivation;
- A good faith estimate of the amount of an project investment and the time period the generator would be required to be out of service for repairs, if any, that would be required to keep the unit in or return the unit to operation.

PJM Generation Department will notify PJM Planning, PJM Markets and the PJM Market Monitoring Unit. PJM will also notify the appropriate transmission owner(s) of the request with the agreement of the generation owner or designated agent. PJM will initiate preliminary analysis of the request.

Note that only official requests to deactivate a unit are subject to the following procedures and timelines. All official requests are subject to public posting on the PJM website. Any requests to analyze potential retirements will be treated as unofficial requests, and the PJM deactivation process will not begin until and official public request is received.

Initial Analysis

PJM Planning will perform an initial analysis of the request. PJM Planning will perform standard RTEP/MAAC analysis for the affected summer peaks. PJM Planning will also identify maintenance and appropriate sensitivity analyses to be performed in addition to standard tests. PJM will review planned system reserve levels and conduct appropriate deliverability analysis. In addition, the PJM Market Monitoring Unit will analyze the effects of the proposed deactivation with regard to potential market power issues.

Analysis Results

The initial analysis has the following potential outcomes: 1) No reliability or market power issue identified, 2) Reliability or market power issue identified, or 3) Economic or congestion impact identified (PJM identifies potential for additional congestion due to the deactivation)

<u>No reliability or market power issue identified</u>

- If no reliability or market power issue identified, the generator can retire as soon as practicable
- Black start resources will forfeit a maximum of 1 year of revenues per existing tariff. If the unit is a black start resource, PJM will identify feasible alternative sites, and request tariff based bids to replace black start. A bid to re-power (improve) existing resource will be considered. The lowest cost replacement black start resource will be selected.

<u>Reliability or market power issue identified</u>

- PJM will notify the generator owner, or its designated agent, within 30 days of the deactivation request if a reliability issue has been identified. This notice will include the specific reliability impact resulting from the proposed deactivation of the unit, as well as an initial estimate of the period of time it will take to complete the Transmission upgrades necessary to alleviate reliability impact
- *Within 60 days of the original deactivation request, the generator owner or* designated agent, will provide PJM with an update estimate of any project cost and the period of time for which the unit would be required to be out of service for repairs, if any, that would be required to keep the unit in, or return the unit to, operation.
- Within 75 days of the original deactivation request, PJM will provide an updated estimate of the period of time it will take to complete the Transmission upgrades necessary to alleviate reliability impact

- Within 90 days of initial deactivation request, PJM will inform the generator owner, or designated agent, and post on its web site full details of the transmission upgrades that will be required in order to allow the unit to deactivate.
- Black start resources will forfeit a maximum of 1 year of revenues per existing tariff. If the unit is a black start resource, PJM will identify feasible alternative sites, and request tariff based bids to replace black start. A bid to re-power (improve) existing resource will be considered. The lowest cost replacement black start resource will be selected.

Economic or Congestion Impact Identified

- If PJM identifies an economic or congestion impact (e.g. - potential for additional congestion due to the deactivation), the generator can retire as soon as practicable.
- Black start resources will forfeit a maximum of 1 year of revenues per existing tariff. If the unit is a black start resource, PJM will identify feasible alternative sites, and request tariff based bids to replace black start. A bid to re-power (improve) existing resource will be considered. The lowest cost replacement black start resource will be selected.
- Any economic impacts will be analyzed through the existing FERC approved economic planning process.

Compensation to Generators Requested to Remain in Service for Reliability

Upon receipt of notification from PJM that a generating unit will be requested to operate past its desired deactivation date, the generator owner may file with FERC for full cost recovery associated with operating the unit until it may be deactivated. The cost calculations may be reviewed with PJM prior to filing at the election of the generation owner.

In the alternative, the generator owner, or its designated agent, may choose to receive avoided cost compensation according to the Deactivation Avoidable Cost Credit in Part V of the PJM Tariff. Avoidable expenses are incremental expenses directly required for the operations of a unit proposed for deactivation. The two major components to the avoid cost formula contained in the Tariff are:

- Categories of costs that are avoidable expenses
- Limited amount for necessary investment to keep unit in operable condition

Avoidable expenses do not include variable costs recoverable under cost-based offers to sell energy in PJM Interchange Energy Market Additional investment over and above the limited component in the avoided cost formula must be filed as a separate rate. All inquires regarding avoidable expenses are to be directed to the PJM Market Monitor

If the generation owner, or designated agent, chooses the compensation according to the Deactivation Avoidable Cost Credit in Part V of the PJM Tariff, compensation to the generator will begin as of the day following the filing, and will be net of revenues from the PJM markets. All revenues from the PJM markets and unit-specific bilateral contracts net of marginal cost of service recoverable under cost-based offers to sell energy from operating capacity of the PJM Interchange Energy market, not less than zero

- A 10% adder will initially be applied to the avoidable costs, and this adder will increase in future years. Applicable adders for future years are detailed and defined in Part V of the PJM Tariff.

Costs (avoidable cost rate minus net revenues) will be allocated as an additional transmission charge to the zone (s) for which the Transmission Owner (s) will be assigned the cost of the transmission upgrade.

If a generation owner, or designated agent, chooses to file for full cost of service with FERC, PJM begins crediting the generator the amount approved by FERC, on the timeline ordered by FERC as part of the approval. PJM also allocates the costs associated with these credits according to FERC order.

Exhibit 13 displays the generation deactivation process flow.

Generation Deactivation Process Flow

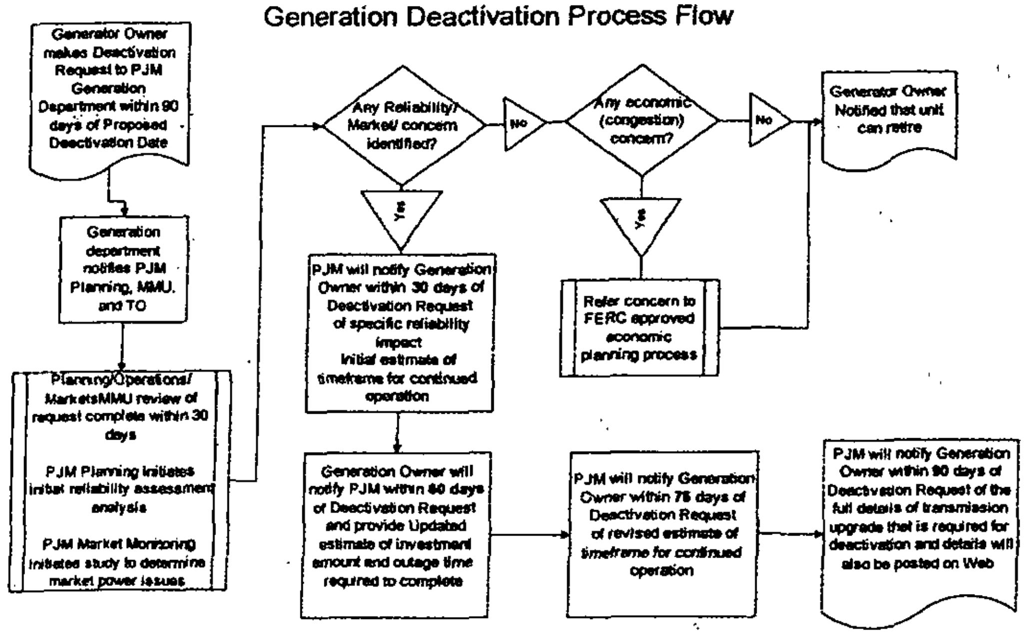

Exhibit 13: Generation Deactivation Process Flow